R.12-03-012: 2012 LTPP
Operating Flexibility Analysis

Nathaniel Skinner

Senior Analyst, Generation & Transmission Planning

California Public Utilities Commission

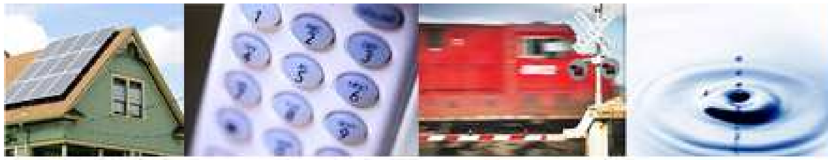
June 4, 2012

Remote Access

- Webex
  https://van.webex.com/van/j.php?ED=183770997&UID=491292852&PW=NM2FmOGYxNTUx&RT=MiM0
  Meeting Number: 743 103 614
  Meeting Password: energy

- Phone
  Call in #:
  866-687-1675
  *Note: *6 to mute/unmute*

  Passcode:
  3481442



Agenda

Time	Item
10:00 - 10:10	Introduction, Schedule Overview
10:10 – 10:20	Expectations, LTPP / RA Interaction
10:20 - 12:00	Status of studies: Past efforts (2010 LTPP) models and methods
12:00 – 1:00	Lunch
1:00 – 2:30	Status of studies: Current/future efforts (2012 LTPP) models and methods
2:30 – 2:45	Break
2:45 – 3:15	Modeling resources: Inside & outside of the CAISO system
3:15 – 3:45	Overview of additional assumptions/metrics needed for studying operational flexibility
3:45 – 4:00	Wrap-up/Next steps

Meeting Purpose

- Familiarize parties with the studies conducted in the 2010 LTPP
- Begin informing parties about current and future studies
- Begin assessing what additional assumptions and metrics beyond those identified in the planning standards are needed for modeling

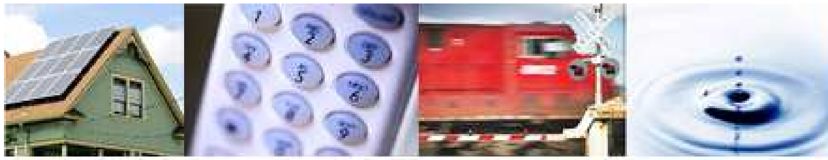
Meeting Purpose (cont)

- What do we want to call these studies?
  - Issues are broader than renewable integration (includes load variability)
  - Broader than variability studies (includes forecast uncertainty)

Study Schedule

- 6/4: Meeting #1
- Mid/late August: Meeting #2
- Mid September: Meeting #3
- Additional schedule TBD

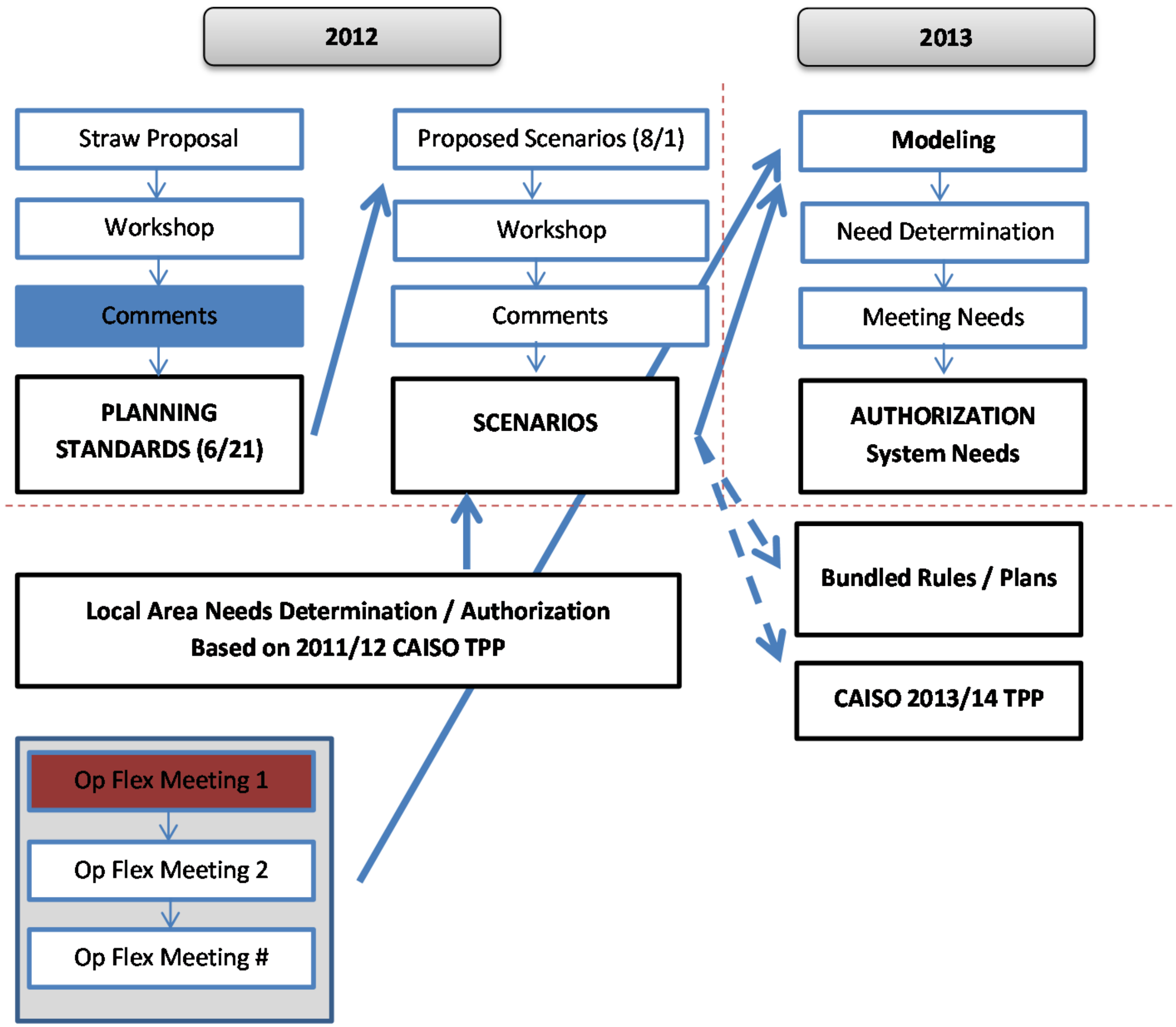
- Schedule for incorporating information into the record will be established in a future ruling

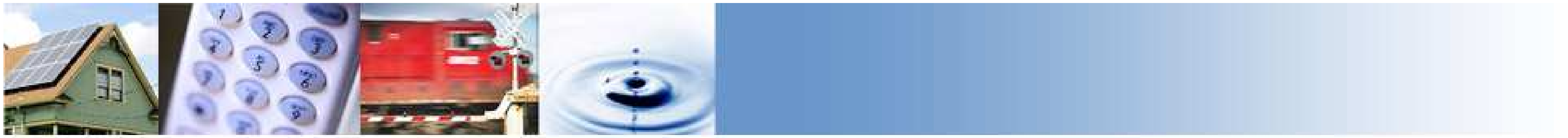


Other Anticipated Schedule

- Track I (Local Area Reliability)
  - 5/23: CAISO testimony on LCR
  - 6/25: Other parties' testimony on LCR
  - 7/9: Second Prehearing Conference
  - 7/23: Reply testimony (all parties)
  - 8/7-10 & 8/13-17: **Evidentiary Hearings**
    - If needed
    - Some subset of days may be selected
  - Nov-Dec: Proposed Decision issued

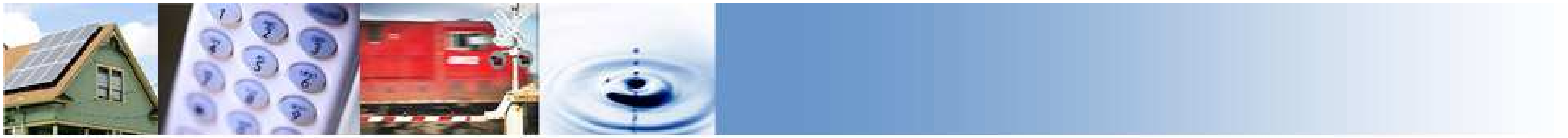
Roadmap


2012
2013
Straw Proposal
Workshop
Comments
PLANNING STANDARDS (6/21)
Proposed Scenarios (8/1)
Workshop
Comments
SCENARIOS
Modeling
Need Determination
Meeting Needs
AUTHORIZATION System Needs
Bundled Rules / Plans
CAISO 2013/14 TPP
Local Area Needs Determination / Authorization Based on 2011/12 CAISO TPP
Op Flex Meeting 1
Op Flex Meeting 2
Op Flex Meeting #



Expectations

- Highly technical studies, parties will need to allocate their resources as they best see fit
- Collaborative process to advance studies
- Any recommended methods or data source changes need to be documented, justified, and cited for consideration



LTPP/RA Interaction

- Work is undergoing to assess interaction between RA (procurement) and LTPP (planning & resource development)
- Need for clear definitions and procedural location to meet both proceedings’ needs

Past Efforts

Operating Flexibility Analysis for R.12-03-014

Mark Rothleder, Executive Director, Market Analysis and Development

Shucheng Liu, Principal Market Developer

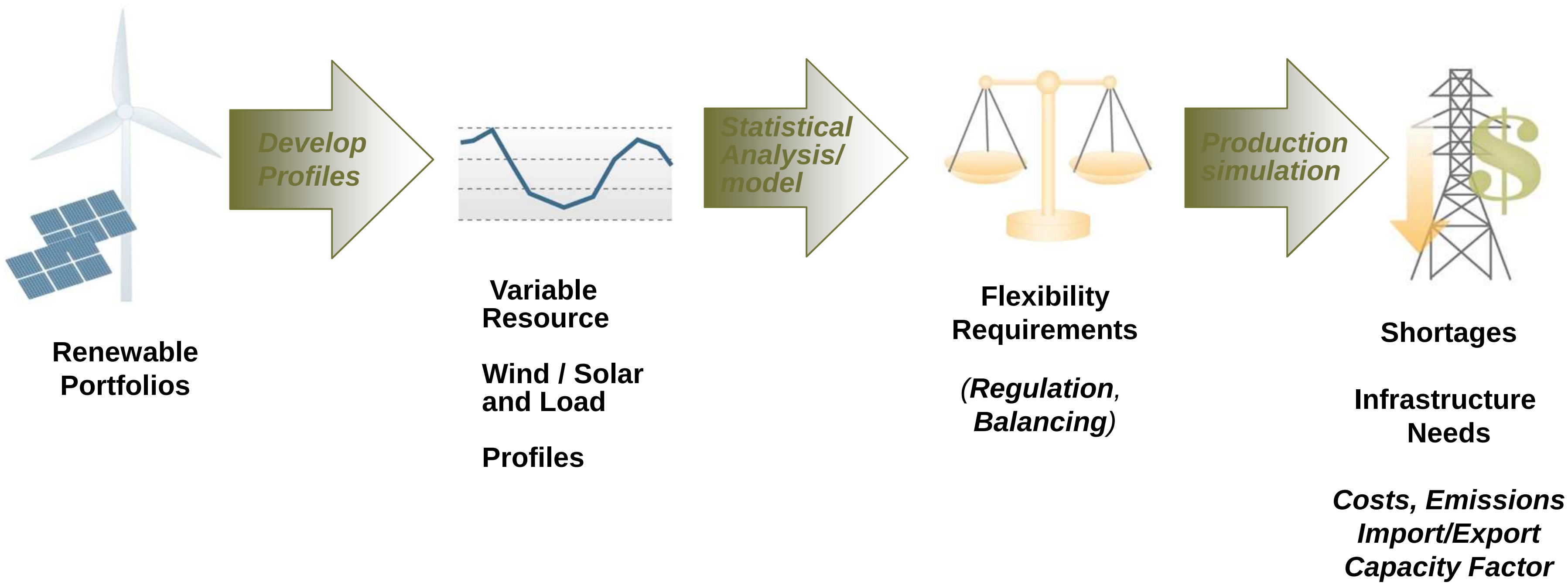
Clyde Loutan, Senior Advisor

Arne Olson , E3

CPUC, Workshop June 4, 2012

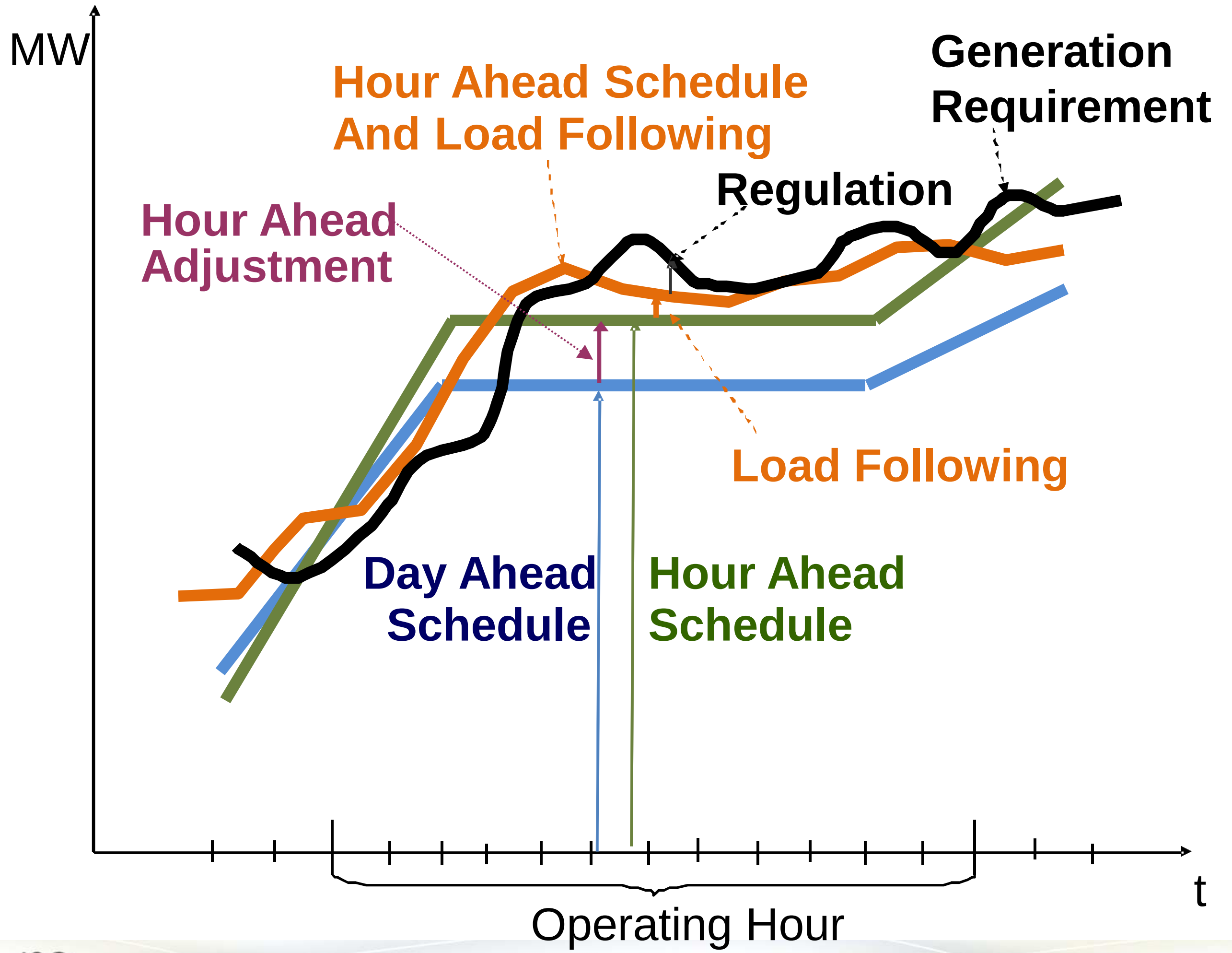
Description of Past Method and Model

Study process quantifies operational requirements and evaluates fleets ability to meet operating requirements.

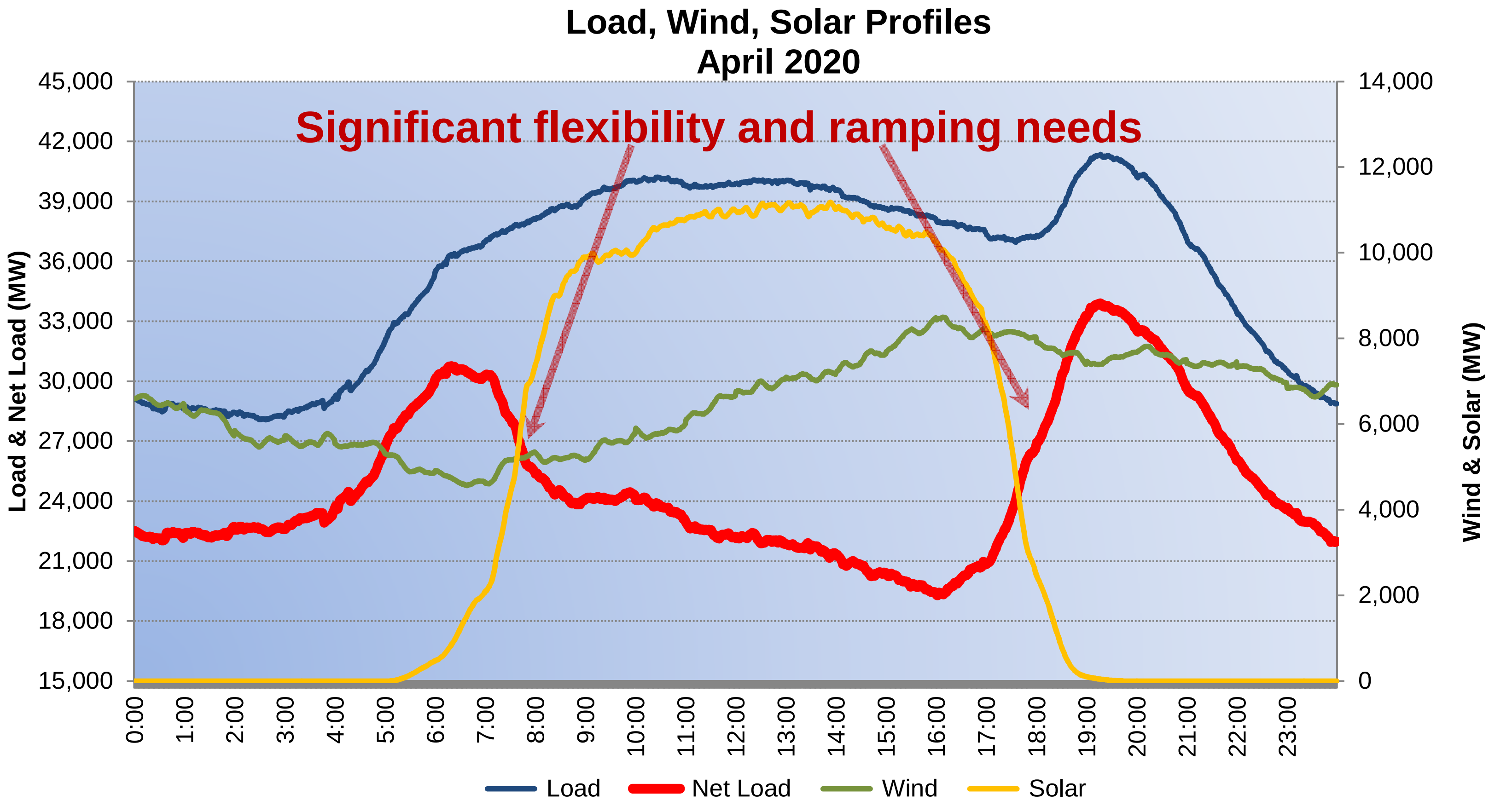


Slide 14

To be prepared for increased supply variability … fleet flexibility requirements must be understood



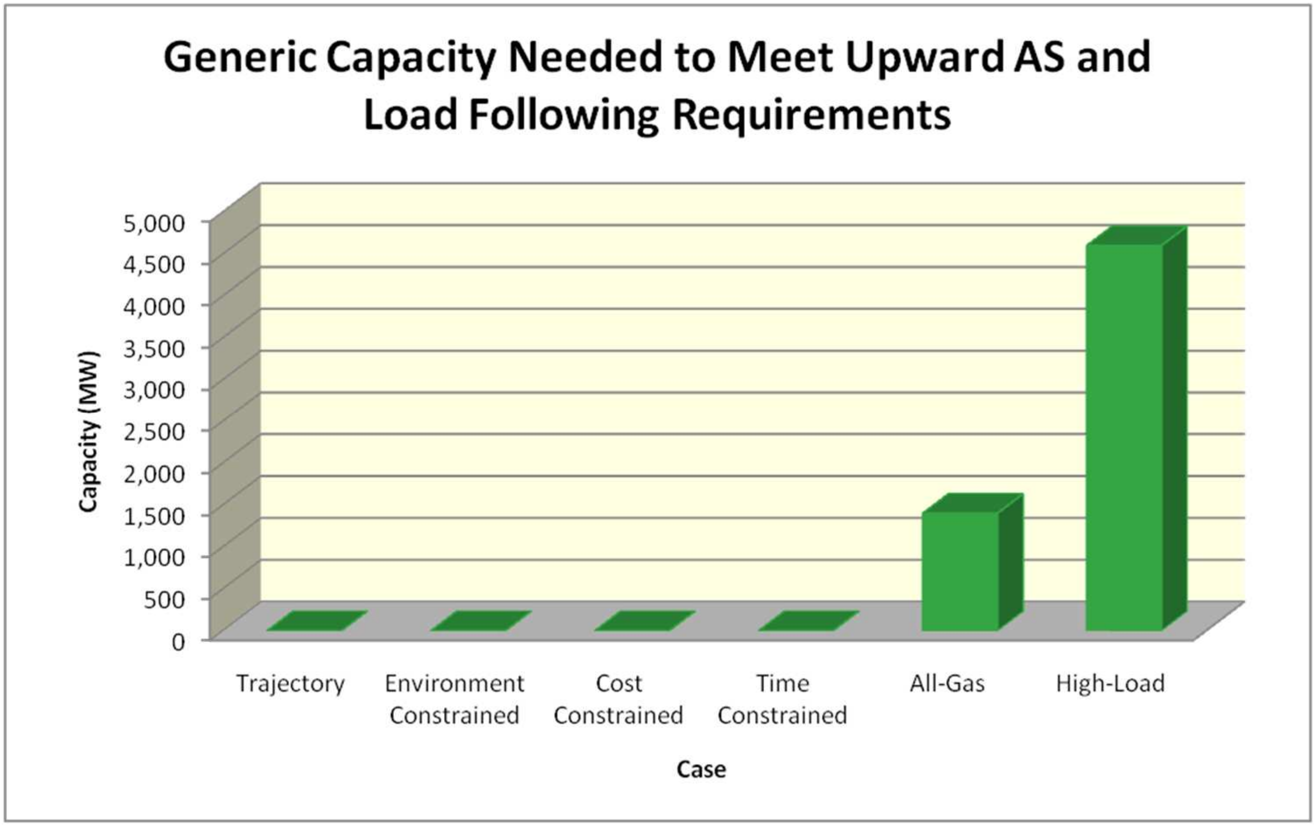
Conventional resources will be dispatched to the net load demand curve



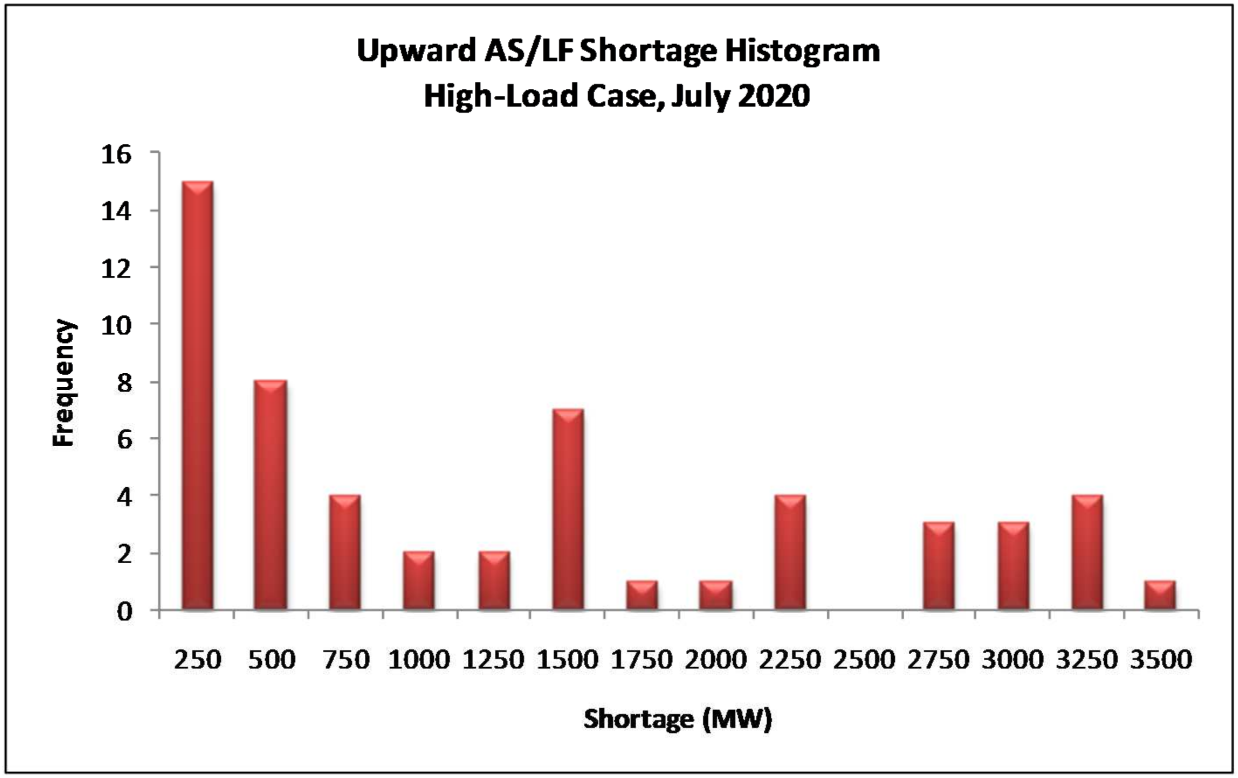
33% scenarios in 2020 cover range renewable and load conditions.

Case	Case Title	Description
1	33% Trajectory	Based on contracted activity
2	Environmental Constrained	High distributed solar
3	Cost Constrained	Low cost (wind, out of state)
4	Time Constrained	Fast development (out-of-state)
5	20% Trajectory	For comparison
6	33% Trajectory High Load	Higher load growth and/or energy program under-performance
7	33% Trajectory Low Load	Lower load growth and/or energy program over-performance

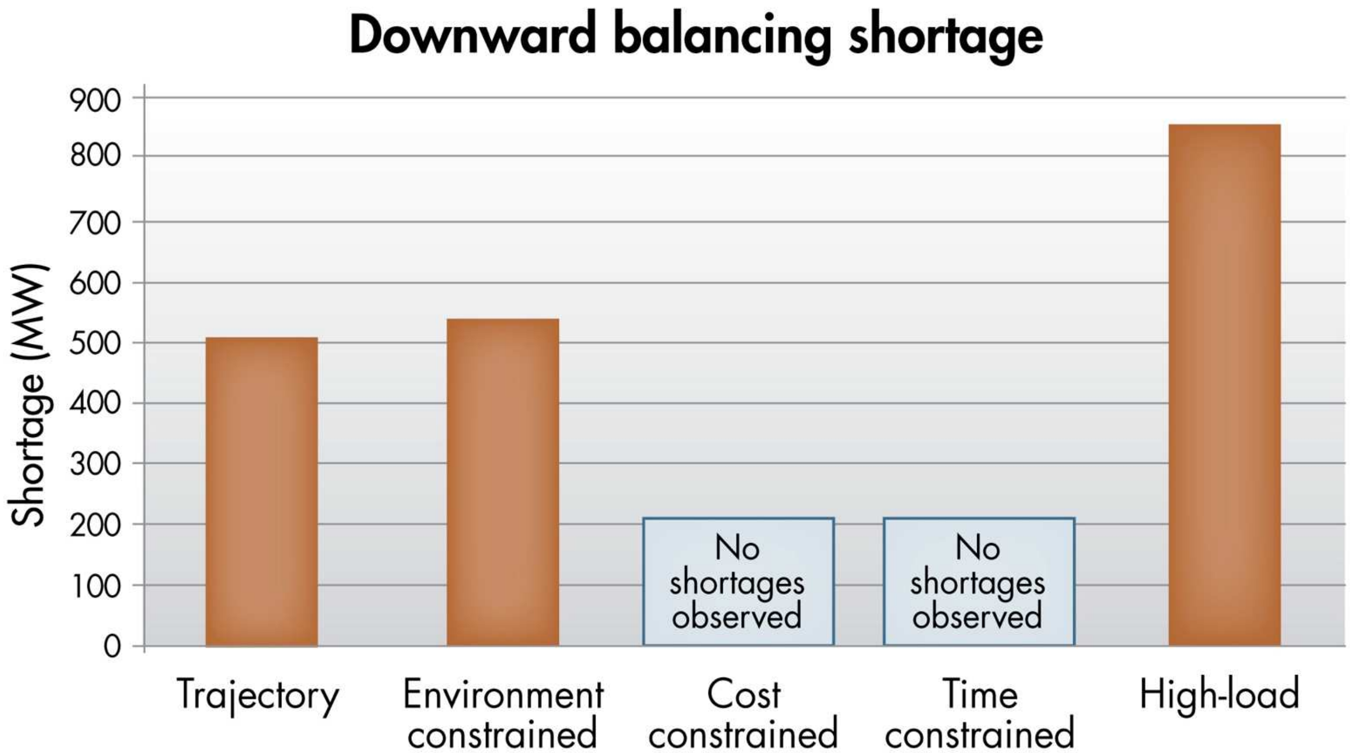
Generic resources are added to meet upward ancillary services and load following requirements in the two cases.



There is a total of 55 hours of shortage observed in July 2020 High-Load Case

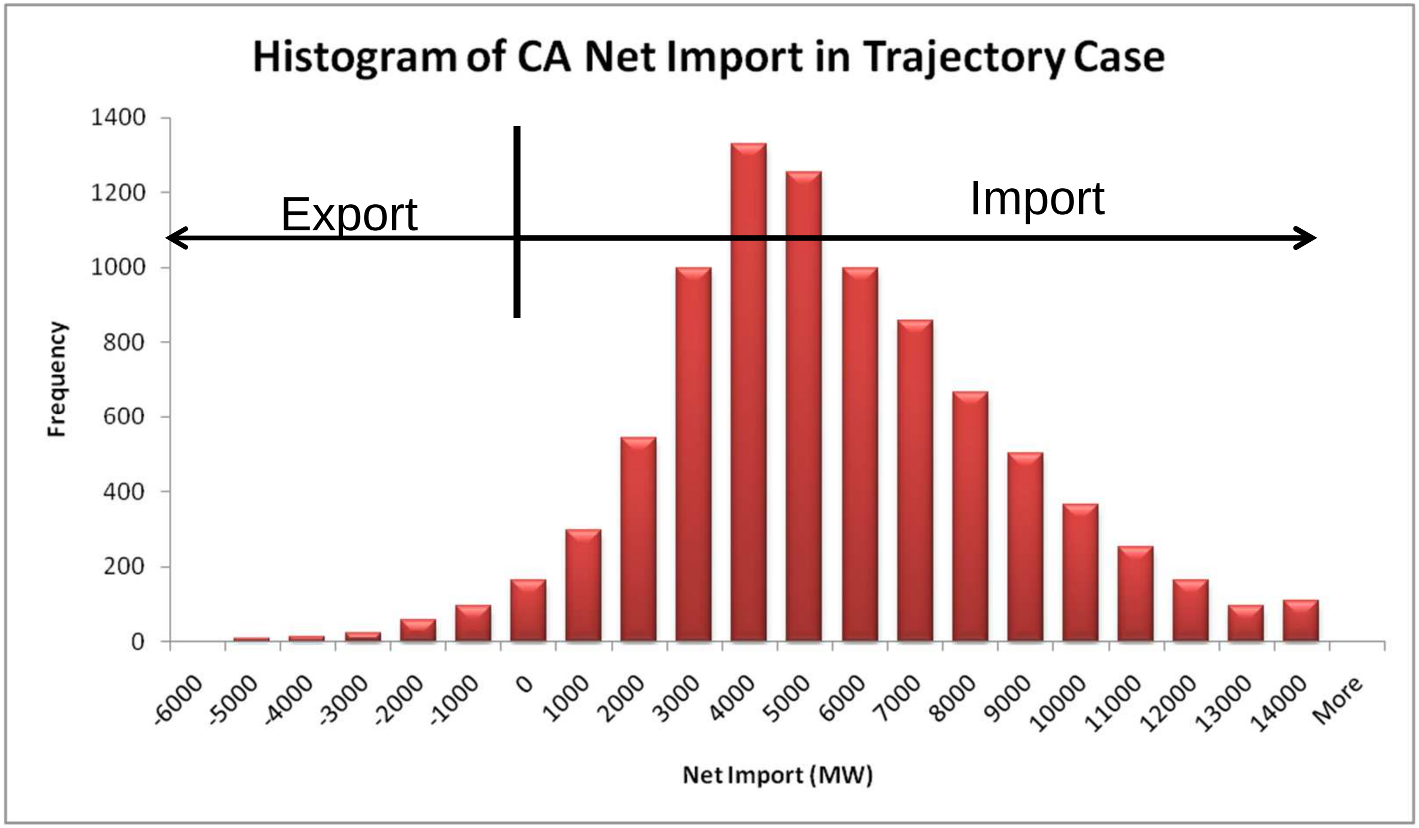


Out of approximately 3,500 MW downward balancing requirements, some hours of potential shortages were observed.



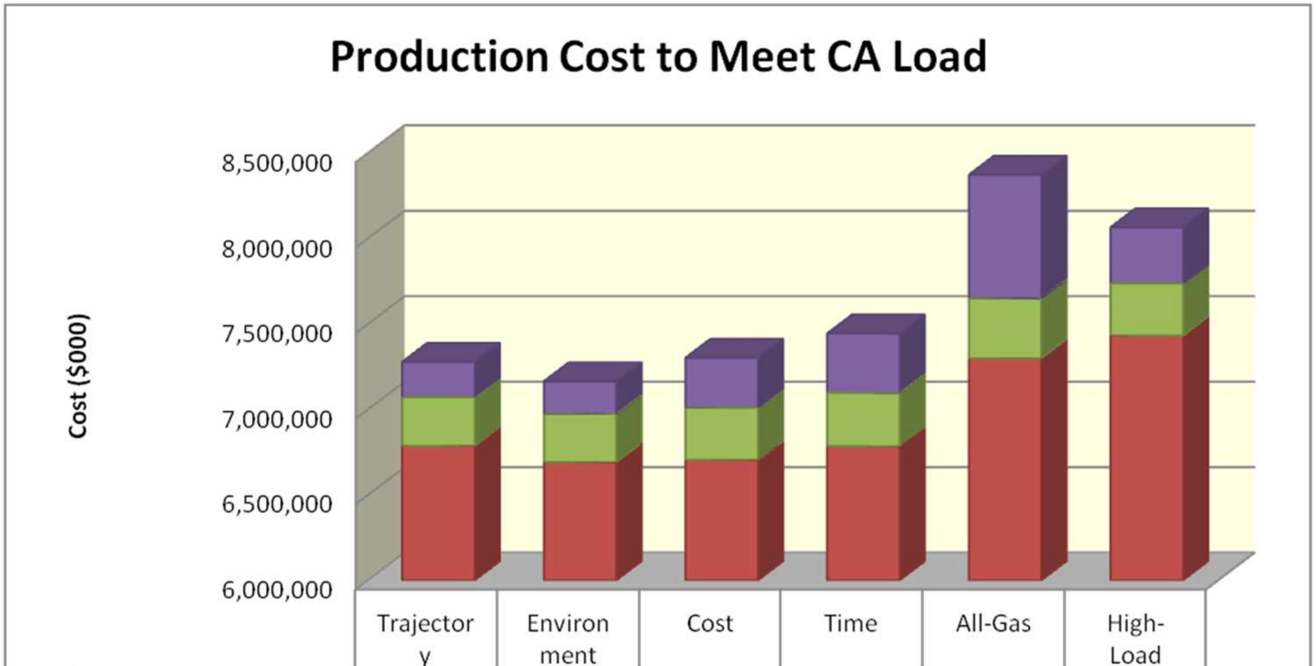
Note: Downward balancing may be more effectively and efficiently managed using curtailment or storage rather than less economic dispatch of flexible resources to higher level to maintain downward flexibility

Large quantity of net export observed in the cases need to be reviewed.



California ISO
Shaping a Renewed Future

Annual production costs associated with California load (accounting for import/exports), by case



	Trajectory	Environment	Cost	Time	All-Gas	High-Load
Non-Dedicated Import	206,096	190,467	292,175	346,793	722,367	327,348
Dedicated Import	285,028	282,620	305,414	312,970	350,287	306,667
CA Generation	6,787,502	6,691,967	6,705,361	6,785,267	7,300,579	7,432,088

Note: Production cost associated with non-dedicated import is calculated based on the average cost ($/MWh) of each of the regions the energy is imported from; for dedicated import it is based on the actual production cost of each of the dedicated resource and its energy flows into CA

Additional sensitivity and analysis performed since July 2011

1. PRM Analysis Deep Dive analysis of PRM
2. Step 1 Sensitivity
3. 5 minute simulation
4. Regional modeling and coordination
5. Incorporate Local Capacity Requirements
6. Frequency Response
7. 2018 risk of retirement

CAISO Deep Dive Analysis

Shucheng Liu

What We Have Learned

- "Deep-dive" analysis showed us that PLEXOS results were being influenced by factors not strictly related to renewable integration needs:
  - Load levels
  - Import availability
  - Hydro production
  - Renewable production during critical hours
- These factors have traditionally been analyzed using techniques other than production simulation
  - Reliability analysis focused on loss of load

"Deep-Dive" Analysis of All-Gas Case

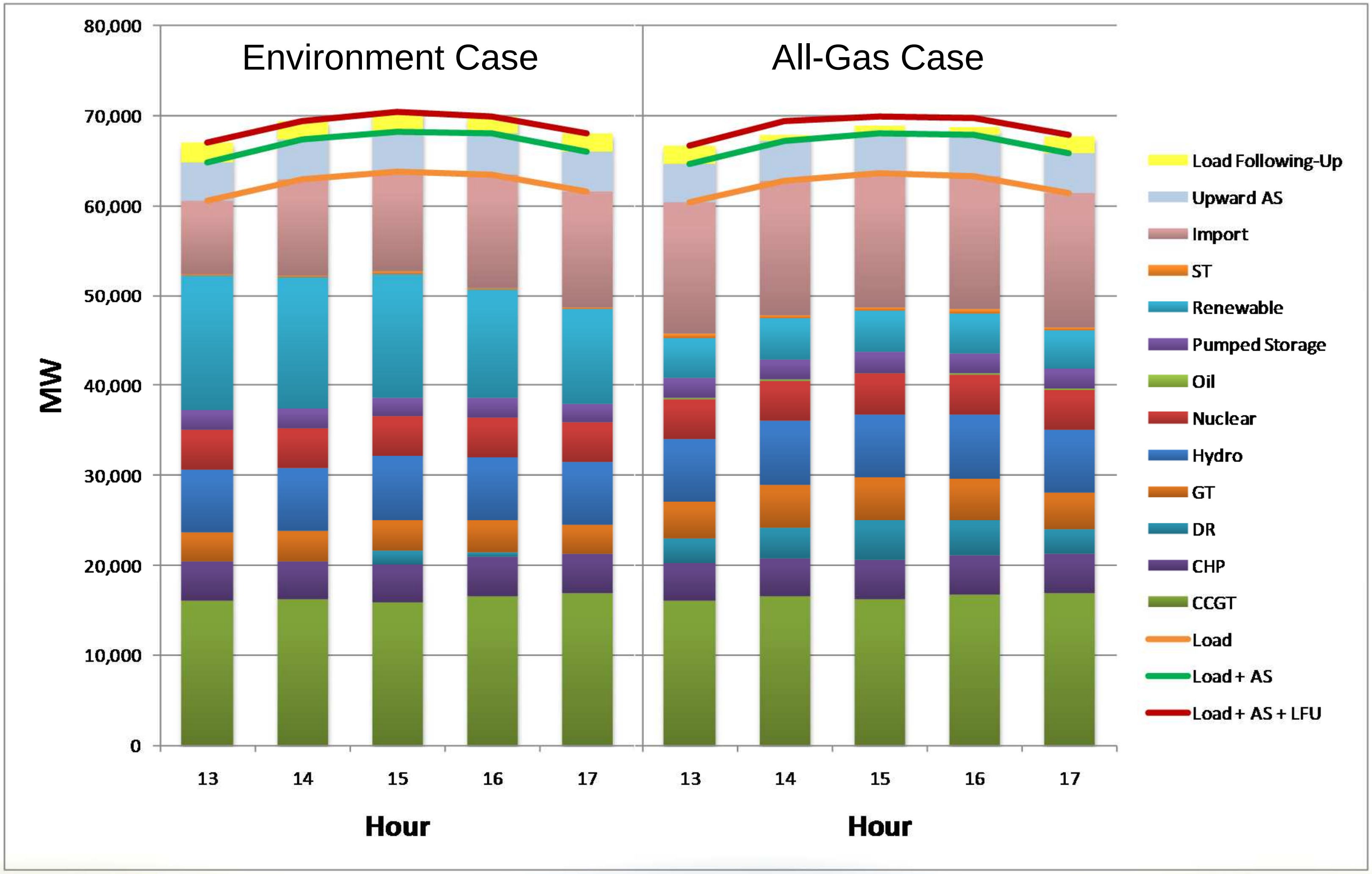
- Previous analysis showed need in All-Gas Case, despite seemingly high reserve margins
- Deep-dive analysis revealed two key factors:
  1. Reserve margin was overstated -- effective PRM for the All-Gas Case is 21%, not 41%
     - Key differences are operating limits on imports, simulated hydro production vs. NQC values
  2. Need in All-Gas Case driven largely by Regulation Up and Load Following Up requirements
     - Accounts for remaining 4% increase above the 17% PRM

Slide 26

Deep dive analysis: 15-17% Planning Reserve Margin (PRM) Case Analysis

- Review of “All-Gas” indicates actual planning reserve margin is 21%
- Results are sensitive to load, imports, hydro and outages
- A portion of needs above traditional PRM attributable to load following requirements

Comparison of California Load and Resource Balance (July 22, 2020)



Update to the Deep-Dive Analysis – E3

Arne Olson, Partner

Energy+Environmental Economics

Lessons Learned from CAISO's 2011 Analysis

CPUC Workshop

June 4, 2012

Arne Olson, E3

Framework of CAISO Integration Analysis

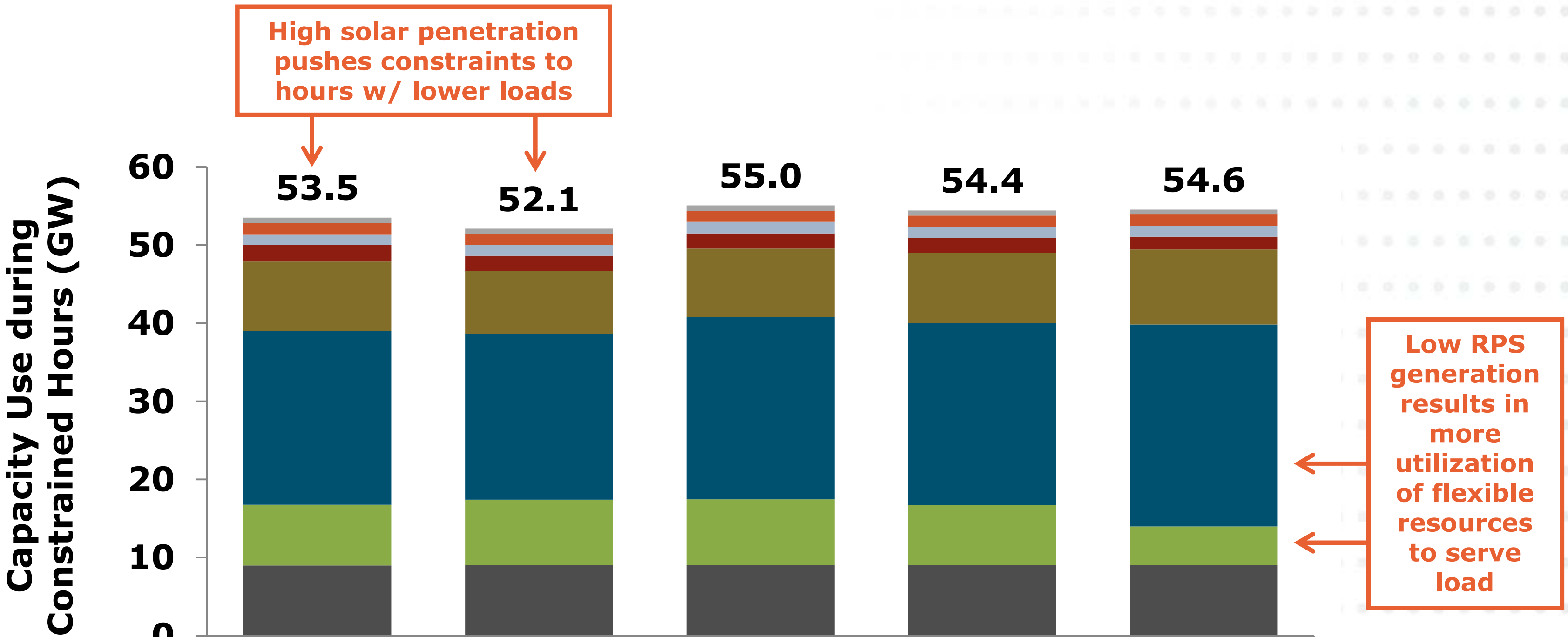
+ **The "Vintage" (2009) cases from the CAISO Integration Analysis were built to the 15-17% PRM before being simulated in PLEXOS to determine integration need**
  - All need for new capacity above PRM was described as "integration need"—need above a threshold that has served as an adequate margin in traditional capacity planning
+ **CAISO's 2011 Integration Analysis relaxed the assumption that the simulated system was built exactly to meet PRM**
  - Instead, the CPUC cases modeled a large capacity surplus due to high achievements of EE, CHP, CSI and the 33% RPS
  - Results were counterintuitive: 1,400 MW of need in All-Gas Case, 0 MW of need in Trajectory Case
+ **This section provides context for these results:**
  - What are the main drivers of need in the CPUC cases?
  - Why is there "integration need" in the All-Gas case?

Decomposing Need Results

- **This analysis focuses on "constrained hours": the 50 hours of the year in which the system's use of flexible resources is the highest, as identified in PLEXOS**
  - Top 50 hours vary by scenario
  - Classifies resources as they are *used*, not based on availability
  - Analysis is based on CAISO "cost" runs instead of "need" runs because data was readily available

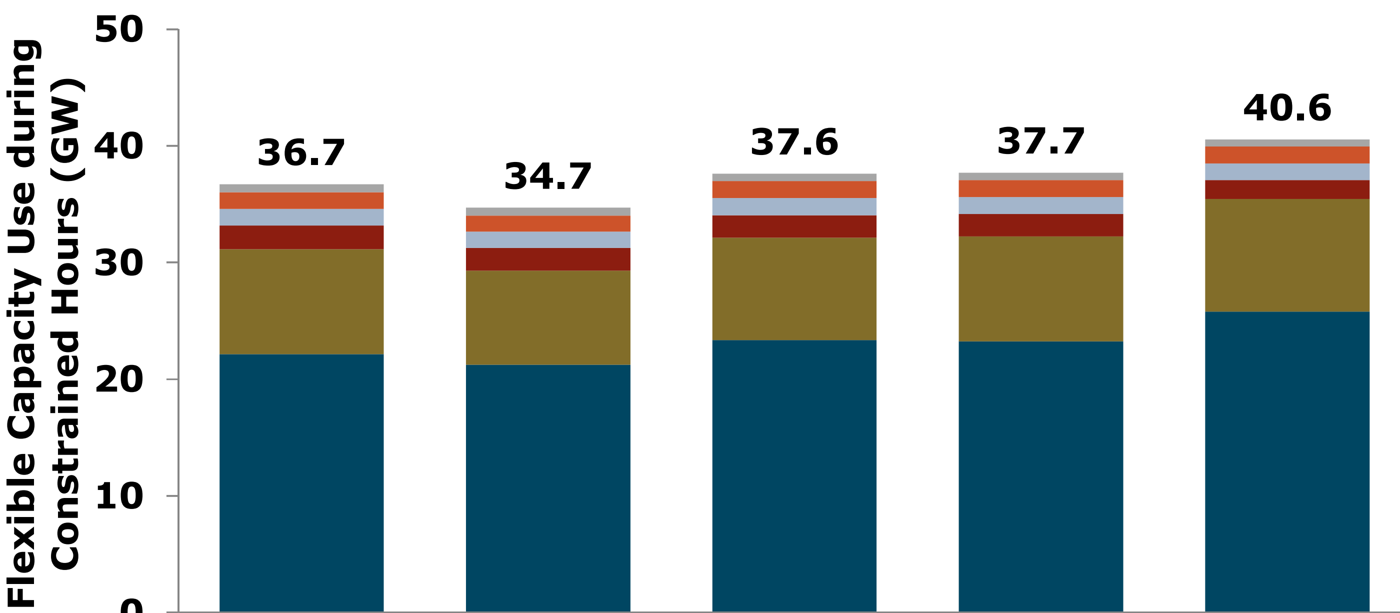
	Flexibility Requirement Based on Demand Side Need			Flexibility Requirement Based on Supply Side Resources
	Load	=		Generation by flexible resources
-	Baseload & RPS generation		+	Imports
+	Upward A/S requirements		+	Upward A/S provision
+	Load following up requirement		+	Load following up provision
=	**System Flexibility Requirement**		=	**System Flexibility Requirement**

CAISO Resource Utilization in Constrained Hours



	Traj	Env	Cost	Time	All Gas
Total	53,518	52,088	55,050	54,440	54,560
Reg Up	690	668	637	653	619
NonSpin	1,426	1,397	1,461	1,445	1,444
Spin	1,426	1,397	1,461	1,445	1,444
LFU	2,042	1,941	1,948	1,931	1,616
Imports	8,979	8,065	8,759	8,978	9,626
Flex Gen	22,168	21,235	23,356	23,255	25,816
RPS Gen	7,782	8,339	8,420	7,714	4,982
Baseload Gen	9,004	9,045	9,008	9,018	9,012

CAISO Flexible Resource Utilization in Constrained Hours



	Traj	Env	Cost	Time	All Gas
Total	36,731	34,704	37,622	37,708	40,565
Reg Up	690	668	637	653	619
NonSpin	1,426	1,397	1,461	1,445	1,444
Spin	1,426	1,397	1,461	1,445	1,444
LFU	2,042	1,941	1,948	1,931	1,616
Imports	8,979	8,065	8,759	8,978	9,626
Flex Gen	22,168	21,235	23,356	23,255	25,816

Largest difference between cases is the amount of flexible capacity use to serve load—not the change in A/S requirements

Breakdown of Differences – Environmental vs. All-Gas

	Component	Environmental Case	All-Gas Case	Difference
	Load	46,685	49,437	2,752
-	Baseload Generation	9,045	9,012	(33)
-	RPS Generation	8,339	4,982	(3,356)
+	Contingency Reserves	2,794	2,888	94
+	Regulation Up	668	619	(49)
+	Load Following Up	1,941	1,616	(325)
=	**Flexibility Requirement**	**34,704**	**40,565**	**5,861**

High solar penetration pushes constrained hours off the peak period in the environmental case

Low RPS penetration in the All-Gas case results in much less RPS generation during constraints

Regulation and load following requirements are slightly higher in the Environmental case, driven by the higher penetration of intermittent resources

Table shows average requirements and resource performance over the top 50 constrained hours

System Need for New Resources

- **The resulting need in the All-Gas case is better described as "system need"**
  - The primary distinction between the All-Gas case and the other four is its net load—**not** its ancillary services requirements
- **The variations in net load are substantially larger than the variations in ancillary services requirements—which suggests that two questions are key to forward-looking capacity planning:**
  1. How high are loads expected to be?
  2. How much renewable generation can be counted on to offset peak loads?
- **Both of these questions lend themselves to more robust analysis through a probabilistic, LOLP-type analysis**

Summary of Flexible Resource Use during Constrained Hours

Scenario	Net Load[1] [MW]	Total A/S Requirement[2] [MW]
Trajectory	31,146	5,585
Environmental	29,301	5,403
Cost	32,115	5,506
Time	32,233	5,475
All Gas	35,442	5,123

[1] Sum of CAISO flexible generation and imports
[2] Sum of load following up, regulation up, and spinning & non-spinning reserves

Lessons Learned

- **Need in PLEXOS-based methodology is sensitive to many factors besides variable energy resource (VER) integration requirements**
  - Load
  - Imports
  - Hydro production levels
  - Renewable resource production during critical hours

All of these factors are bigger drivers of need than flexibility requirements

- **These factors are traditionally addressed through a different type of analysis**
  - Reliability analysis focused on the potential for loss of load
- **Need to calibrate California’s fleet based on these other factors before evaluating whether it has enough flexibility to accommodate VER**

Step 1 Sensitivity Work

Clyde Loutan

Step 1 Sensitivity

- Purpose:
  - Review and improve representation of variability and forecast error parameters for load/wind/solar being used in the study
- Scope:
  - To estimate Step 1 requirements for sue in Plexos simulations or stochastic simulations
- Study Approach:
  - Bracket range of forecast errors for wind and solar (PV and CST) based on past forecast experience and reasonable achievable forecast improvements
  - Where there is little or no forecast experience (PV and CST) use a range based on other studies or industry knowledge of forecast errors
  - Develop a range of forecast errors and corresponding Step 1 inputs to use in Plexos and in stochastic simulations
  - Refinement of forecast error for solar thermal should be incorporated

What wind forecast errors should we use in our studies?

Wind	Persistent	Hours	Spring	Summer	Fall	Winter
Current Errors used in Studies	T-1	All	4.0%	3.8%	3.2%	3.1%
2010 PIRP HA Forecast Errors	PIRP	All	10.5%	8.9%	8.4%	6.7%
Future Studies						
Upper Limit Persistent (T-1)	PIRP	All	8.4%	7.1%	5.3%	3.9%
Lower Limit Persistent (T-30)	PIRP	All	2.9%	2.3%	1.8%	1.4%

- T-1 for the Trajectory case would be used for the Step 1 analysis
- PIRP T-1 and T-30 forecast errors would be used as the upper and lower bounds to bookend load-following and regulation requirements

Current solar HA forecast errors used in Step 1 studies

Technology	Persistent	Hours	0<=CL<0.2	.2<=CL<0.5	.5<=CL<0.8	.8<=CL<1.0
Large PV	T-1	Hours 12-16	3.5%	6.9%	5.6%	2.3%
Large solar Thermal	T-1	Hours 12-16	6.0%	10.9%	10.8%	3.0%
Distributed PV	T-1	Hours 12-16	2.2%	4.7%	3.9%	1.8%
Customer Side PV	T-1	Hours 12-16	1.6%	3.3%	3.1%	1.6%

Proposed solar HA forecast errors upper and lower bounds by technology for Step 1 studies

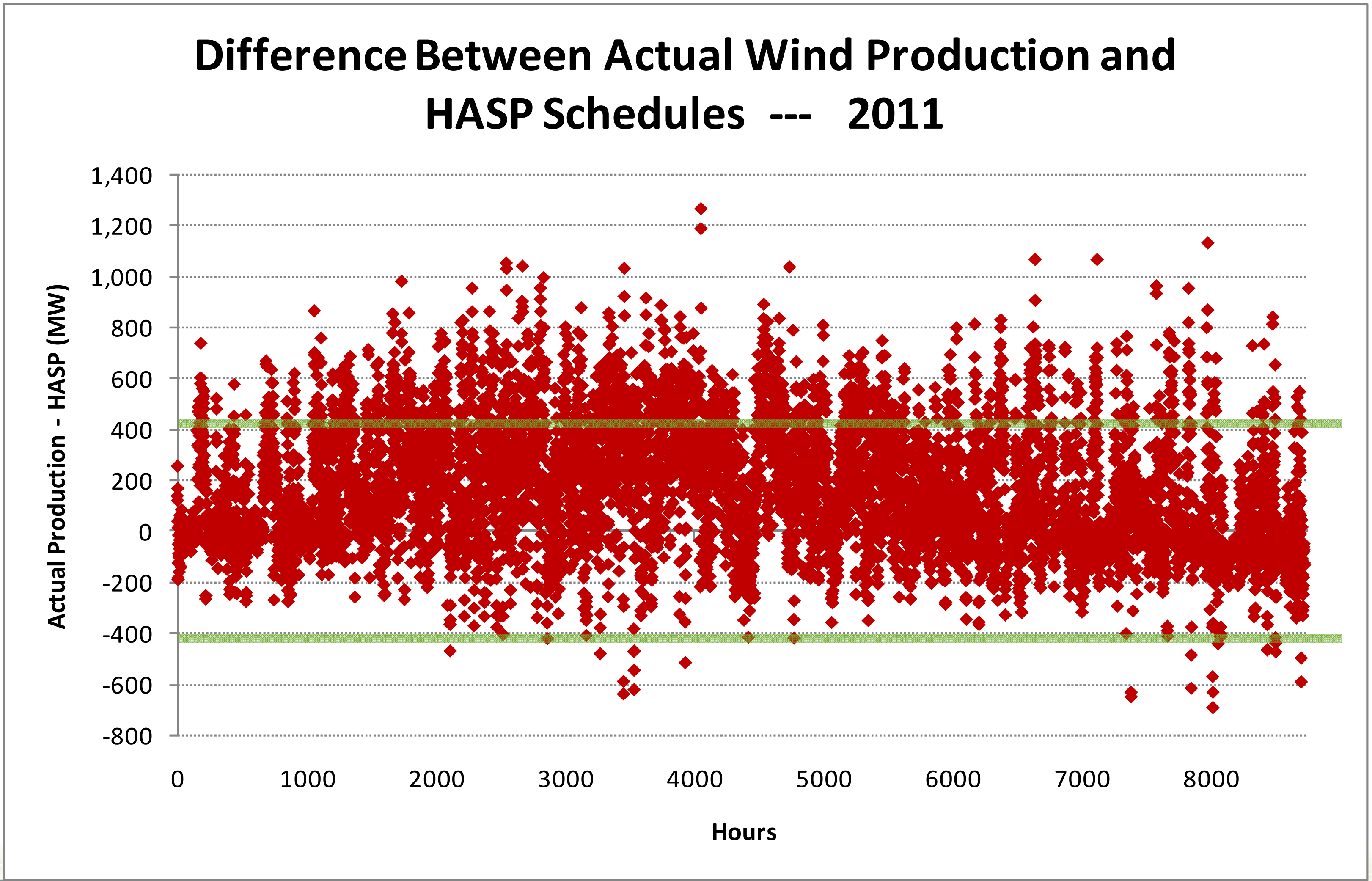
Technology	Persistent	Hours	0<=CI<0.2	0.2<=CI<0.5	0.5<=CI<0.8	0.8<=CI<=1
Large PV (PV) Upper Limit	(T-1) + 20%	12-16	4.20%	8.28%	6.72%	2.76%
Large PV (PV) Lower Limit	(T-1) - 20%	12-16	2.80%	5.52%	4.48%	1.84%
Large Solar Thermal (ST) Upper Limit	(T-1) + 20%	12-16	7.20%	13.08%	12.96%	3.60%
Large Solar Thermal (ST) Lower Limit	(T-1) - 20%	12-16	4.80%	8.72%	8.64%	2.40%
Distribute PV (DG) Upper Limit	(T-1) + 20%	12-16	2.64%	5.64%	4.68%	2.16%
Distribute PV (DG) Lower Limit	(T-1) - 20%	12-16	1.76%	3.76%	3.12%	1.44%
Customer Side PV (CPV) Upper Limit	(T-1) + 20%	12-16	1.92%	3.96%	3.72%	1.92%
Customer Side PV (CPV) Lower Limit	(T-1) - 20%	12-16	1.28%	2.64%	2.48%	1.28%

Current and proposed Load HA forecast errors for Step 1 studies

Load	Hours	Spring MW	Summer MW	Fall MW	Winter MW
Current HA Forecast Errors used in Studies (2010 Actual)	All	545	636	540	682
RT Forecast Errors (2010 Actual)	All	216	288	277	231
High Load Forecast Errors	All	611	700	602	764
Current HA Forecast Errors used in Studies (2011)	All	517	1002	662	622
RT Forecast Errors (2011)	All	243	264	290	255

- 2010 HA and RT forecast errors used for all scenarios
- High Load HA Forecast Errors used for the High Load Case

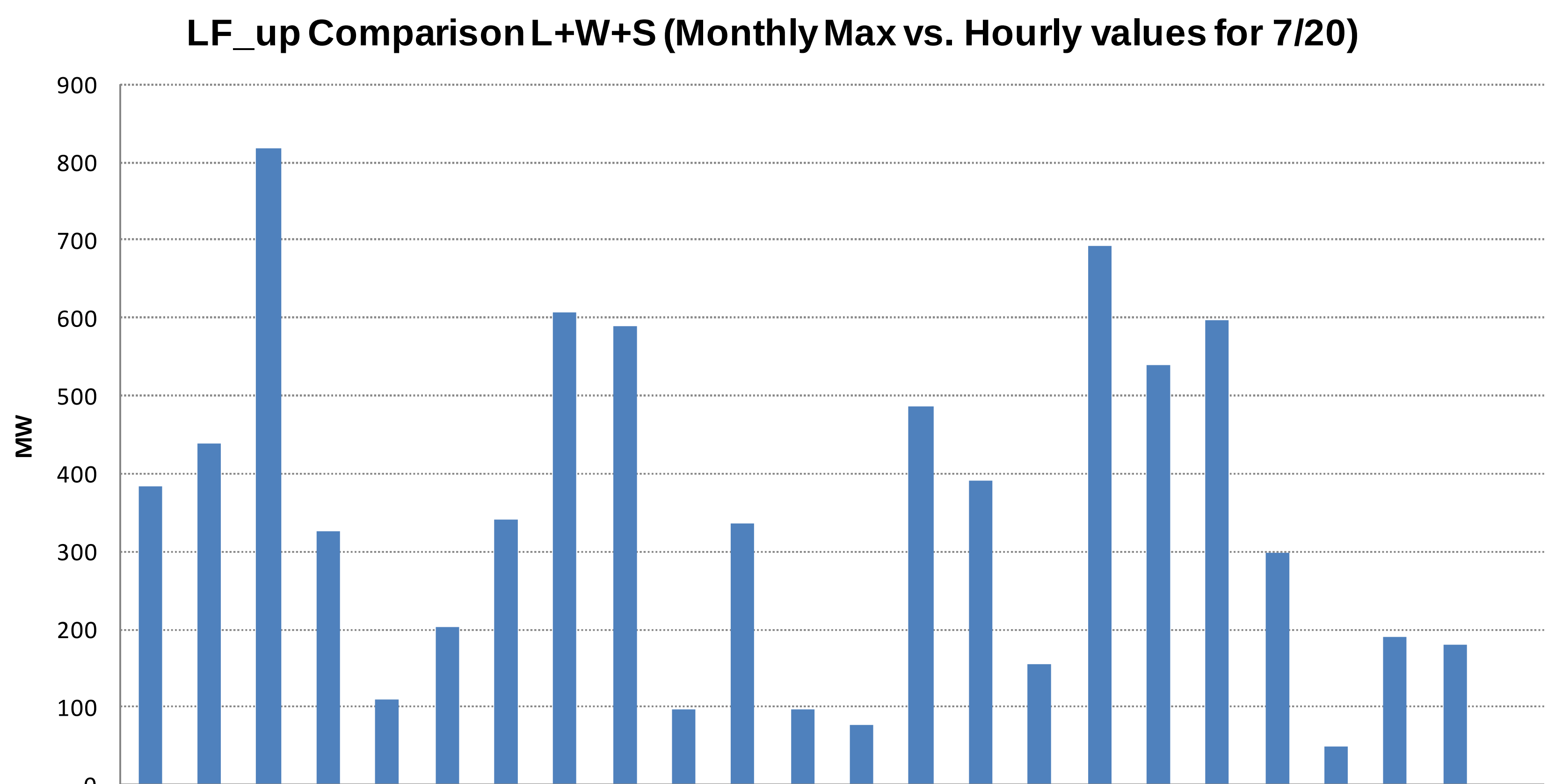
Difference between actual wind production and HASP schedules --- 2011



Green lines represents ±3 σ (mean absolute error of 4%)

Slide 44

Load-following difference between monthly maximum and hourly values for July 20



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
LF_up	382	438	818	325	109	202	342	607	588	97	336	97	77	487	390	155	693	538	596	298	50	191	180	0

California ISO
Shaping a Renewed Future

What data should be passed from Step 1 to Step 2

Average hourly load values are used in production simulation for all 8760 hours including the peak hour (Preferred)

- **Regulation values passed to Step 2**
  - Pass on the maximum (95 percentile) hourly values as is currently done for all hours
- **Load Following values passed to Step 2**
  - **Needs Requirement**
    - Pass on hourly load-following values (95 percentile) from Step 1 for all hours
  - **Cost Requirements**
    - Pass on hourly load-following values (95 percentile) from Step 1 for all hours

The 95 percentile values are truncated from the seasonal values because of the larger sample size

5-minute simulation

Shucheng Liu

5-minute Production Simulation

- Purpose
  - To validate findings from hourly production simulations
- Scope
  - Based on 2020 High-Load case
  - Selected days with upward ramping capacity shortage
- Schedule
  - Complete simulation in November, 2011

5-minute Production Simulation - Ramping Constraints

- 10-min upward AS constraint

$$AS_i \leq 10 \times RampRate_i$$

- 20-min upward AS and LF constraint

$$AS_i + LFU_i \leq 20 \times RampRate_i$$

- Total ramping capacity constraint

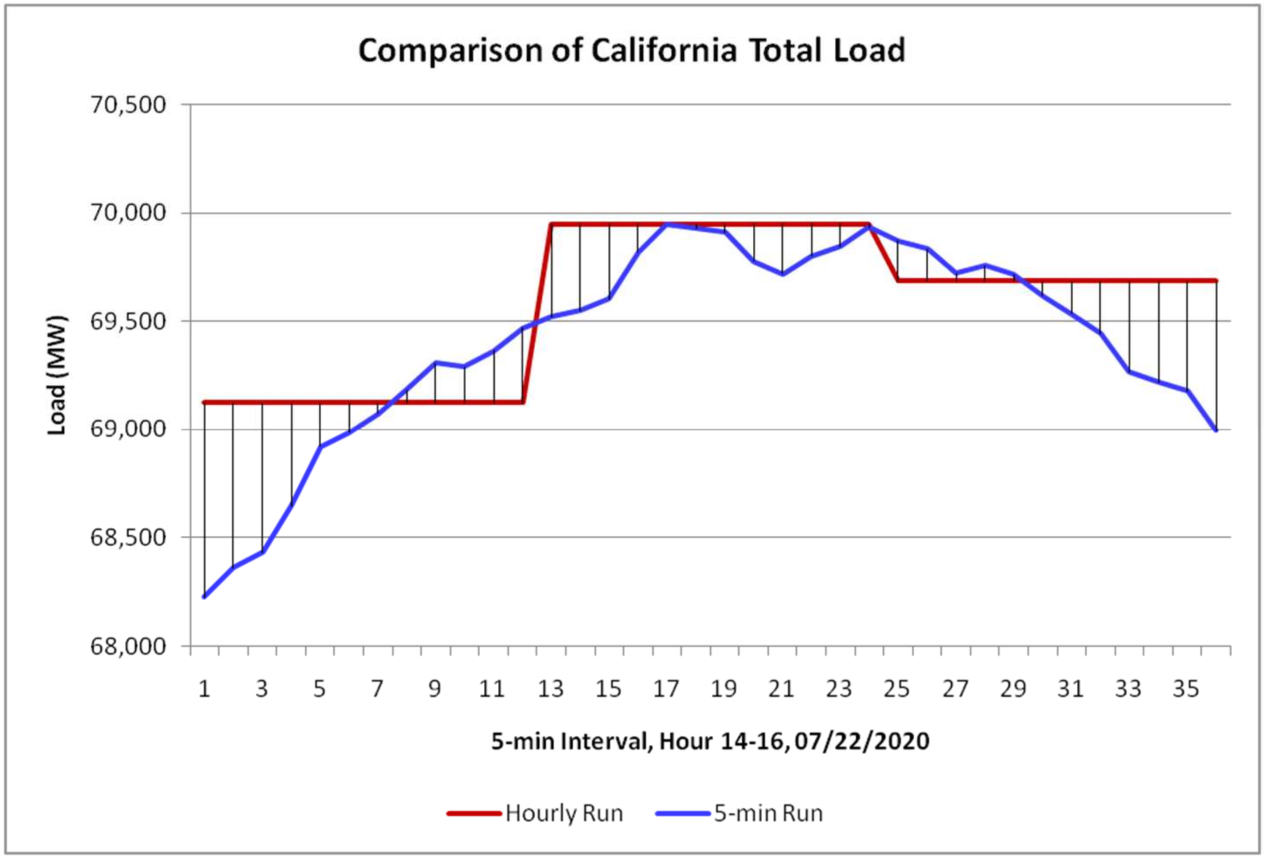
$$12 \times E_i + AS_i + LFU_i \leq 60 \times RampRate_i$$

E_i – 5 – min energy dispatch AS_i – upward ancillary service contribution LFU_i – load following up contribution

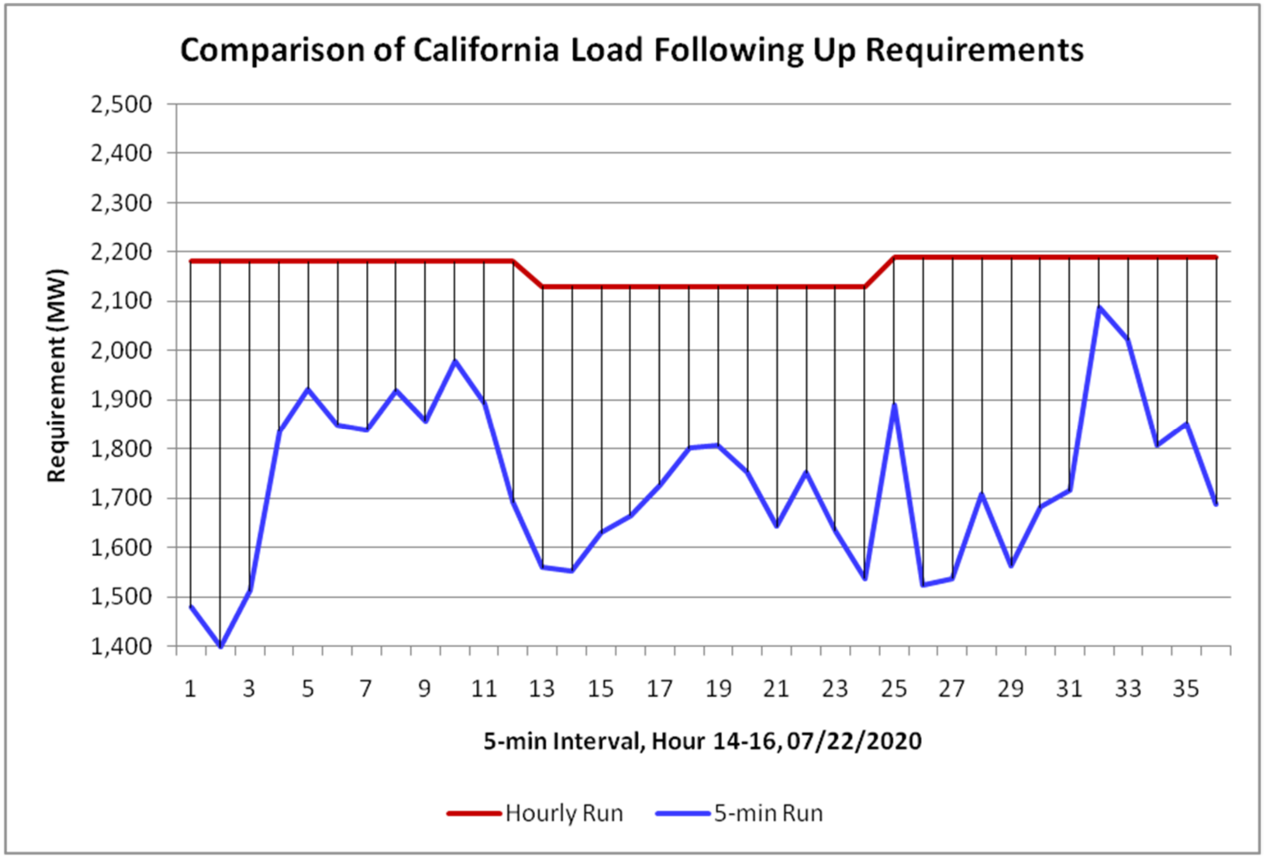
5-minute Production Simulation – Summary of Results

- Load profiles
  - There is a small difference between the 5-min load profile and hourly load profile as the two came from different sources.
- Load following-up requirements
  - 5-min requirement is lower than hourly as it considers forecast errors only
- 20-min ramping capacity shortage
  - 20-min ramping capacity shortage exists in all 5-min intervals in the three hours simulated
  - Interval 8 of HE 16 has highest shortage in 5-min simulation due to large increase in load following-up requirement and ramping constraints

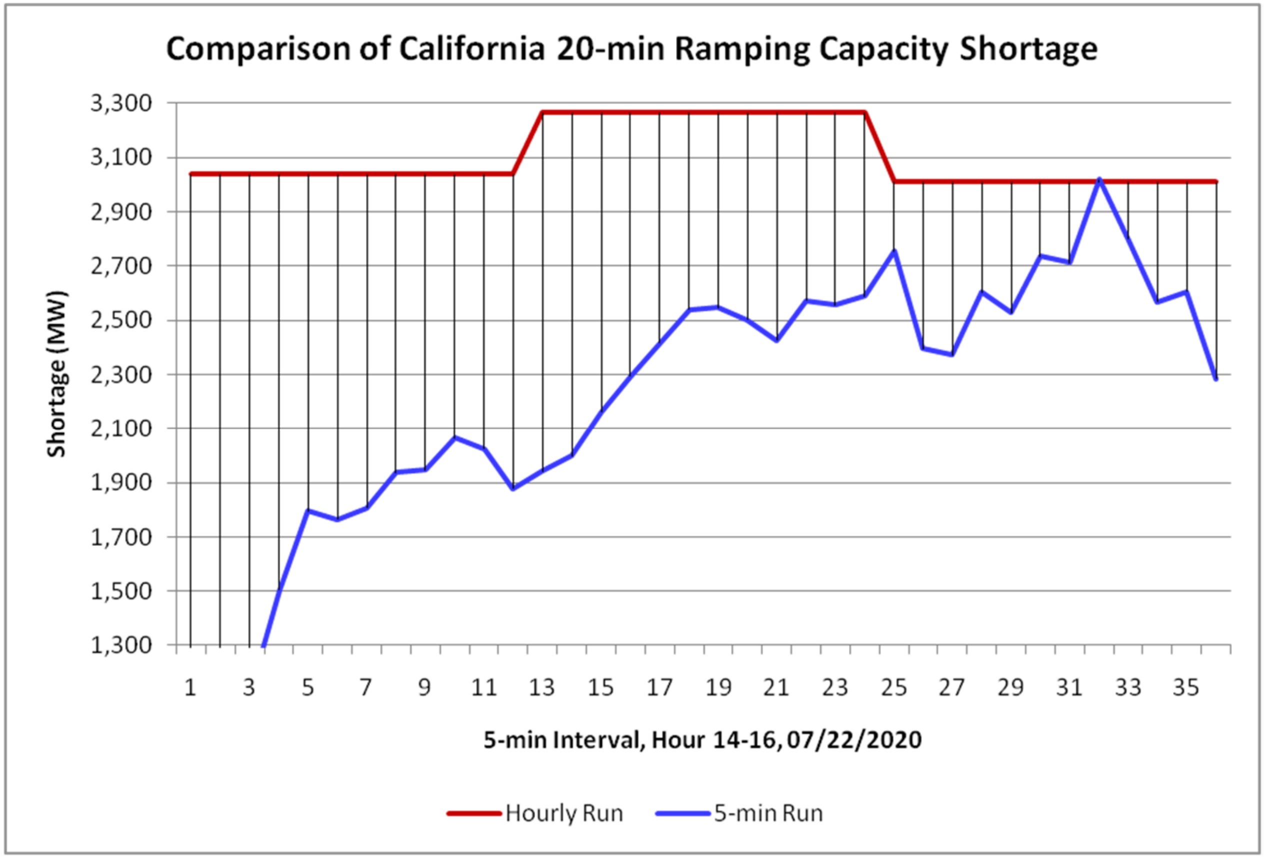
5-minute Production Simulation – Comparison of Load Profiles



5-minute Production Simulation - Comparison of Load Following-Up Requirements



5-minute Production Simulation - Comparison of 20-min Ramping Capacity Shortages



Regional Modeling

Mark Rothleder

Regional modeling and coordination

- Purpose

The renewable integrations studies to date have assumed existing inter balancing authority area operations:

- – Intertie scheduling is predominantly hourly schedules
  - 40% of renewable imports
- – Dynamic transfer will accommodate some transfers:
  - Existing dynamic scheduled resources
  - 15% of renewable imports
- – Intra-hour schedule (15 minute scheduling)
  - 15% of renewable imports
- – Ancillary services provided by existing resources specific system imports.

The renewable integrations studies to date have also assumed:

- – Outside of CA, BAAs have no contingency, regulation, or load following requirements

Regional modeling and coordination changes: WECC reserve requirements modeled

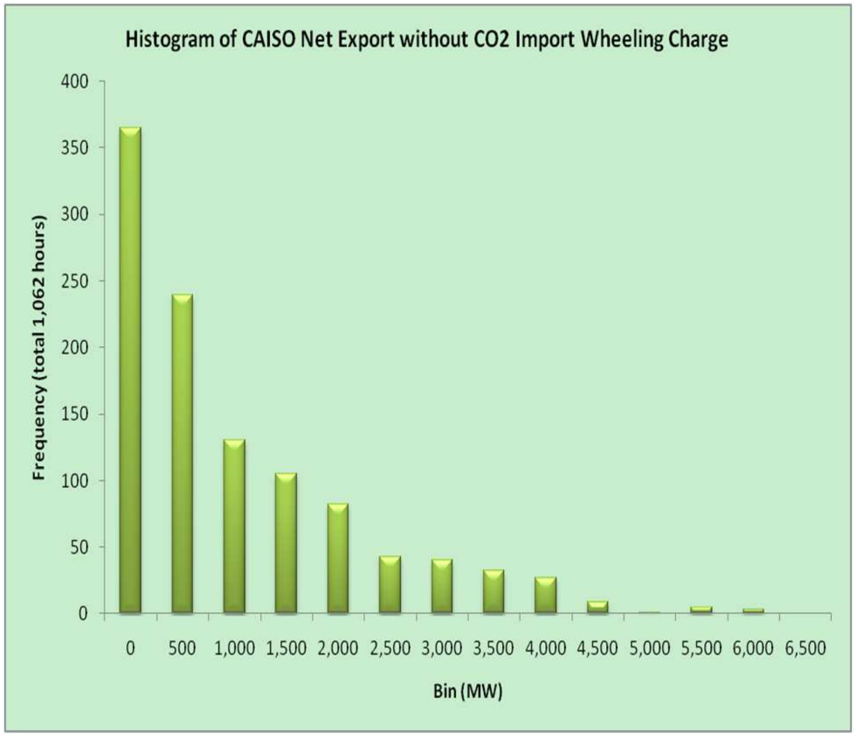
- Modeled reserve requirement in the WECC
  - spinning reserve requirement = 3% of regional load
  - non-spinning reserve requirements = 3% of regional load
  - regulation = 1% of regional load
  - Load following will be based on EIM study assumption
- Defined resources in WECC to provide reserves
  - CCs, CTs and dispatchable (above minimum) hydro; exclude baseload
  - Coal
- Represented Large Coal as more flexible
  - Jointly owned resources: Pmin = 70% of Pmax
  - Other large coal: Pmin=50% of Pmax

Regional modeling and coordination: CO_2 Adder representation

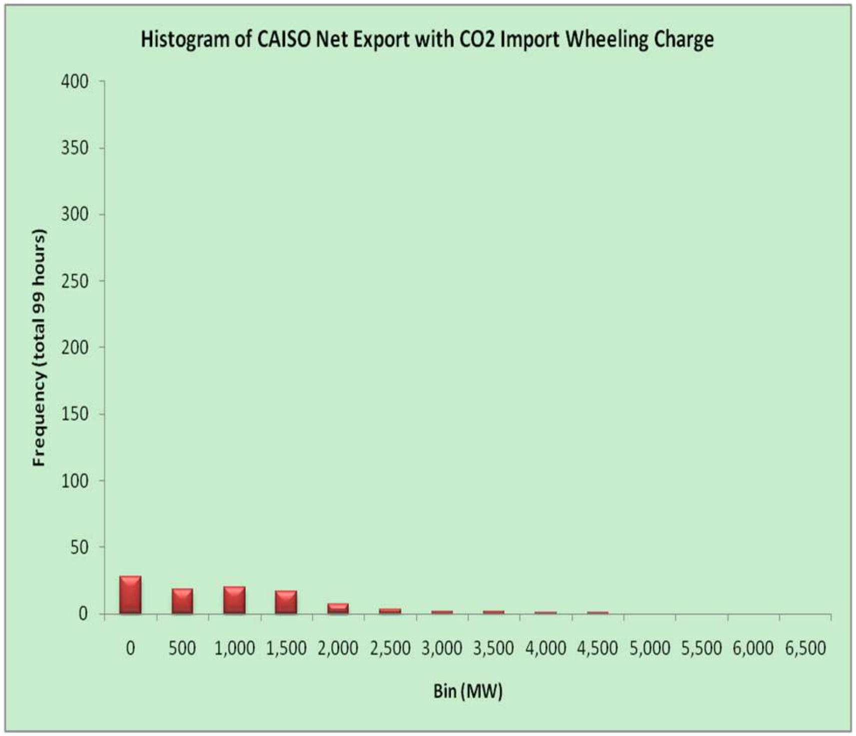
- CA
  - CO_2 adder in CA remained $36.60/Ston
- WECC (except CA and BPA)
  - Replace adder with hurdle rate
  - Hurdle rate = 0.435 MTons/Mwh * 36.3 $/STon * 1.102 (Ston/Mton) = $17.4 /Mwh
- BPA
  - 20% x $17.4/Mwh = $3.48/Mwh
  - Refer to ARB rules http://www.arb.ca.gov/regact/2010/ghg2010/ghgisoratta.pdf

Regional modeling changes to GHG and coal flexibility modeling results in reduction in net exports

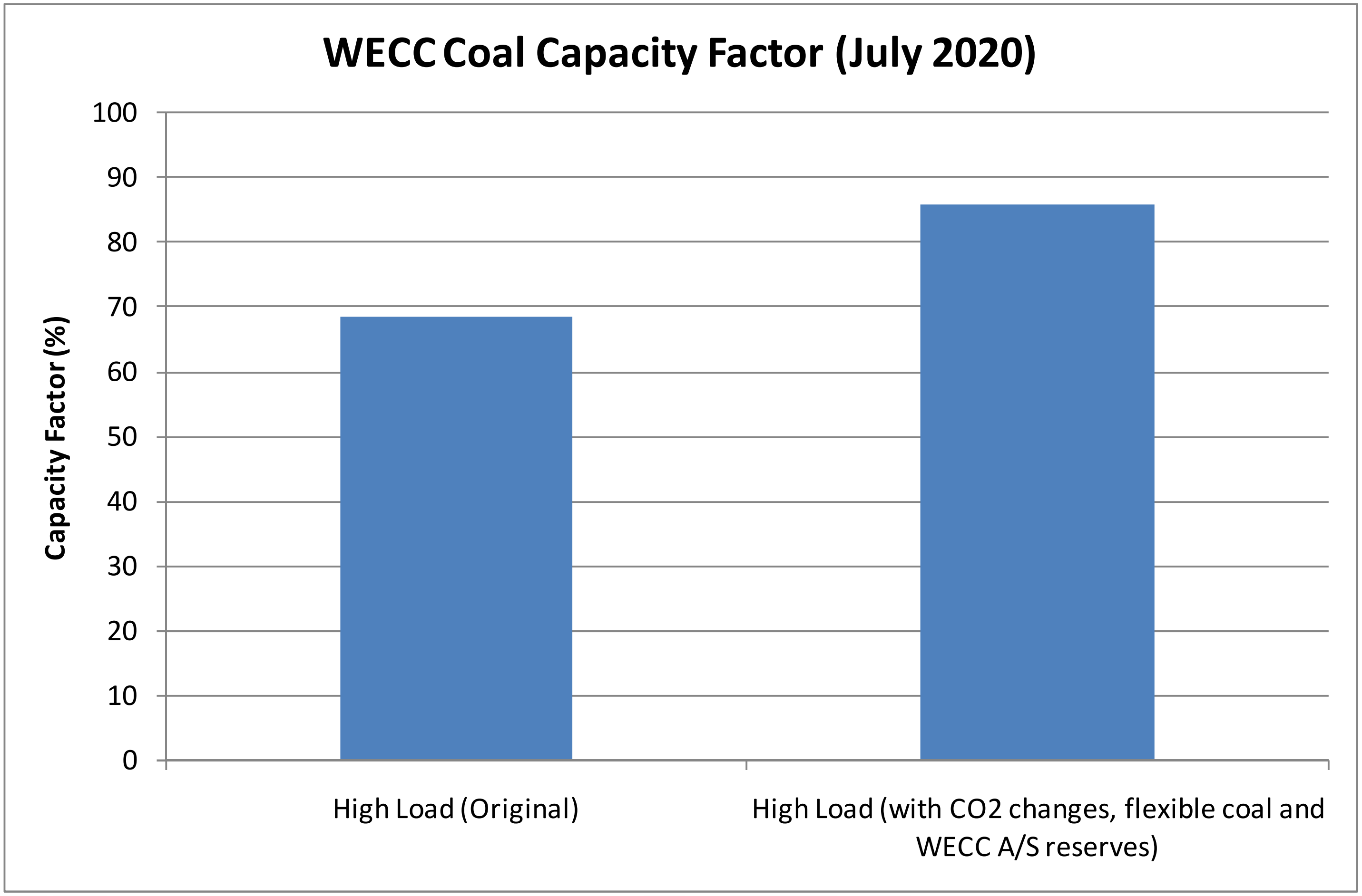
Before: Net Export 1,062 hours
Maximum export=6,478MW



After: Net Export 99 hours
Maximum export = 4,815MW



Study Group 5: Changes to GHG and coal flexibility modeling observed increase capacity factor of external Coal resources.



Incorporate Local Capacity Requirement

Approximately 1,200MW of residual need observed after incorporating LCR resources.

- Total 3,173 MW Local Capacity Requirement (LCR) resources
- A combination of CCGT and GT
  - 1,800 MW GT in SCE region
  - 1,000 MW CCGT in SCE regulation
  - 373 MW CCGT in SDG&E region
- Four hours in July 2020 with shortage observed
- A maximum 1,051 MW 20-minute ramping capacity shortage
- Equivalent to about 1,200 MW residual need for capacity

High-Load Trajectory case LCR resources monthly average capacity factors in production cost-run.

	1	2	3	4	5	6	7	8	9	10	11	12
CCGT - CA Average	42.2%	37.9%	34.6%	29.1%	30.3%	37.4%	61.9%	62.8%	52.9%	46.1%	40.4%	43.4%
GT – CA Average	6.5%	7.1%	5.3%	5.4%	5.4%	5.4%	9.8%	7.9%	4.3%	4.4%	5.4%	5.9%
SCE LCR CCGT	78.8%	79.2%	79.4%	78.4%	78.1%	77.6%	83.0%	83.7%	81.2%	80.6%	79.7%	79.6%
SCE LCR LMS100	10.2%	13.5%	12.0%	10.4%	10.6%	16.2%	21.3%	19.8%	8.2%	10.3%	8.4%	10.5%
SDGE LCR CCGT	79.1%	79.6%	78.5%	79.8%	78.4%	78.8%	83.2%	84.3%	80.8%	80.4%	79.6%	79.9%

Note: Emissions limitations not modeled.

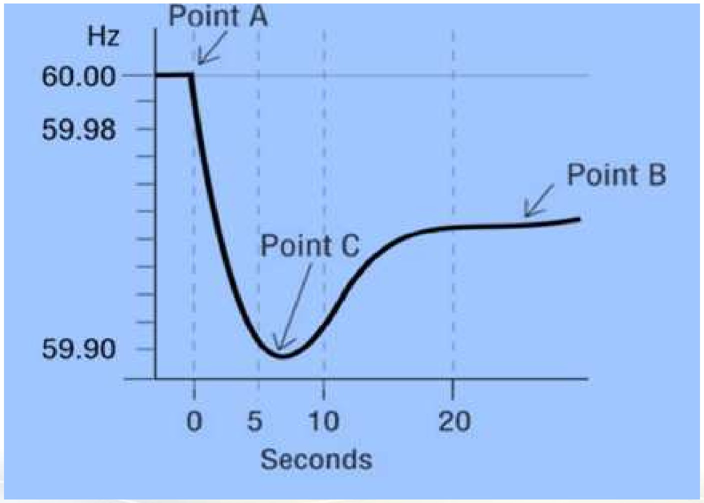
- SCE LCR CCGT – 2 x 500 MW CCGT units, each unit has Pmin = 200 MW, ramp rate = 7.5 MW per minute
- SCE LCR LMS100 – 18 x 100 MW GT units, each unit has Pmin = 50 MW, ramp rate = 12 MW per minute
- SDGE LCR CCGT – 1 x 373 MW CCGT unit with Pmin = 200 MW, ramp rate = 7.5 MW per minute

Frequency Response

Clyde Loutan – Senior Advisor, CAISO

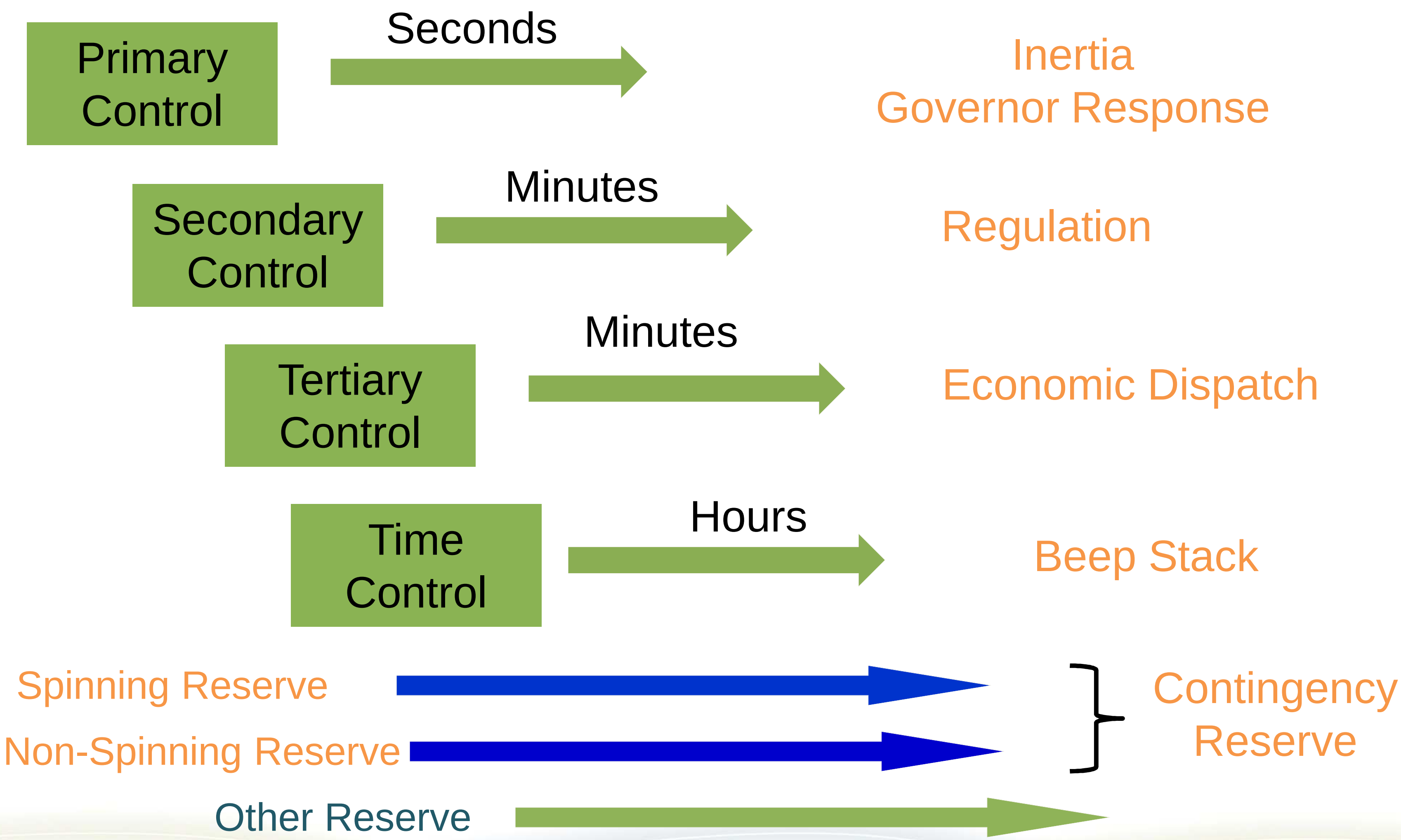
Summary of operational impacts to manage a grid that is more complex

- Increased frequency and magnitude of operational ramps across various time-frames
- Increased frequency and magnitude of over-generation conditions
- Increased intra-hour load-following up and down requirements … need for additional reserves? …or a new product?
- Increased requirements for regulation Up/Down
- Impact of DER and non-traditional resources on the transmission grid is still not fully understood
- Lack of common standards and clarity of existing standards
- Concerns of arresting frequency post contingency
- Inadequate tools to assess the system in real-time



Slide 64

Impacts of Renewable Resources on Frequency Control



Slide 65

The assessment of a balancing authority control performance is based on three components

- **CPS1 -** measures the control performance of a BA's by comparing how well its ACE performs in conjunction with the frequency error of the Interconnection

- **CPS2 -** is a 10-minute statistical measure of a BA's ACE magnitude and is designed to limit unscheduled power flow (currently being waived due to BAAL field trial)

- **DCS -** is the responsibility of the BA following a disturbance to recover its ACE to zero if its ACE just prior to the disturbance was greater than zero or to its pre-disturbance level if ACE was less than zero - within 15 minutes

Control Performance Rating

Pass is when CPS1 ≥ 100%; CPS2 ≥ 90% & DCS = 100%

Slide 66

Real-time operators focuses on several key attributes to ensure reliability

- **Balancing Authority ACE Limit (BAAL)**
  - Load Following/Flexibility
  - BAAL limits cannot be exceeded for more than 30-minutes
  - BAAL allows a large ACE if frequency is close to 60 Hz
- **Hourly Inadvertent Energy**
  - Tracked on-peak and off-peak
  - Impacts neighboring BAs
- **Frequency Control**
  - Maintaining resource/load balance (Regulation)
  - ACE and ΔFrequency (CPS1)
- **Ability of the System to ride through faults without shedding load**
  - Inertia/Frequency Response (NERC standard under development)
  - CPS2 would be replaced with a frequency response obligation

Slide 67

The ability of the system to ride through faults without shedding any load depends on several factors

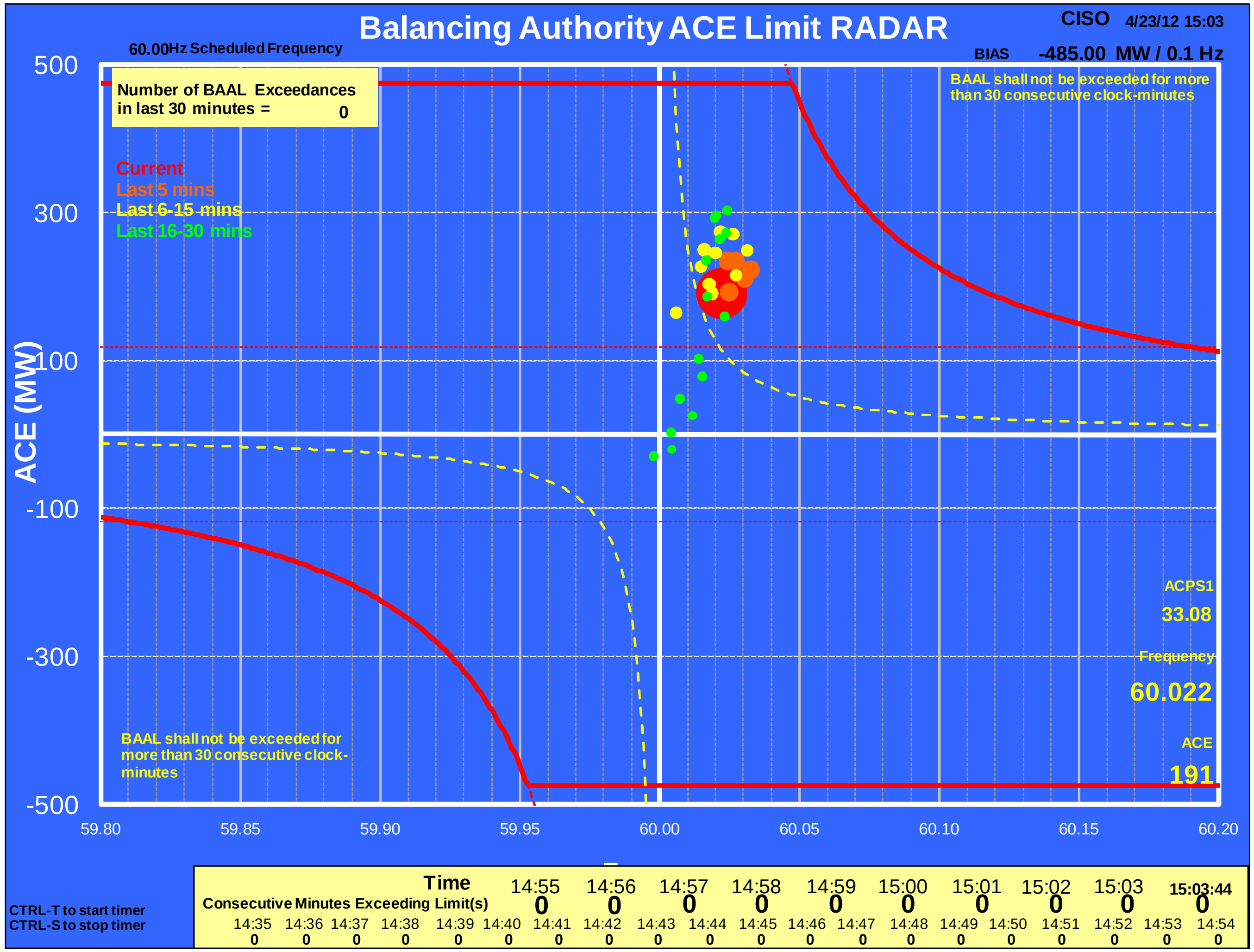
- System conditions before the fault
- Size of the outage
- Inertia of the system
  - Lower system inertia due to increased renewable penetration increases the frequency dip immediately following disturbances
- Headroom available on synchronized resources
- Number and speed of governors providing frequency response
- GE/ISO study
  - Practical headroom for resources within the ISO is ~3,100 MW
  - Headroom includes spinning reserve
  - Headroom does not include upward regulation capacity
  - Headroom does not include Load Following/Flexibility up requirement

Slide 68

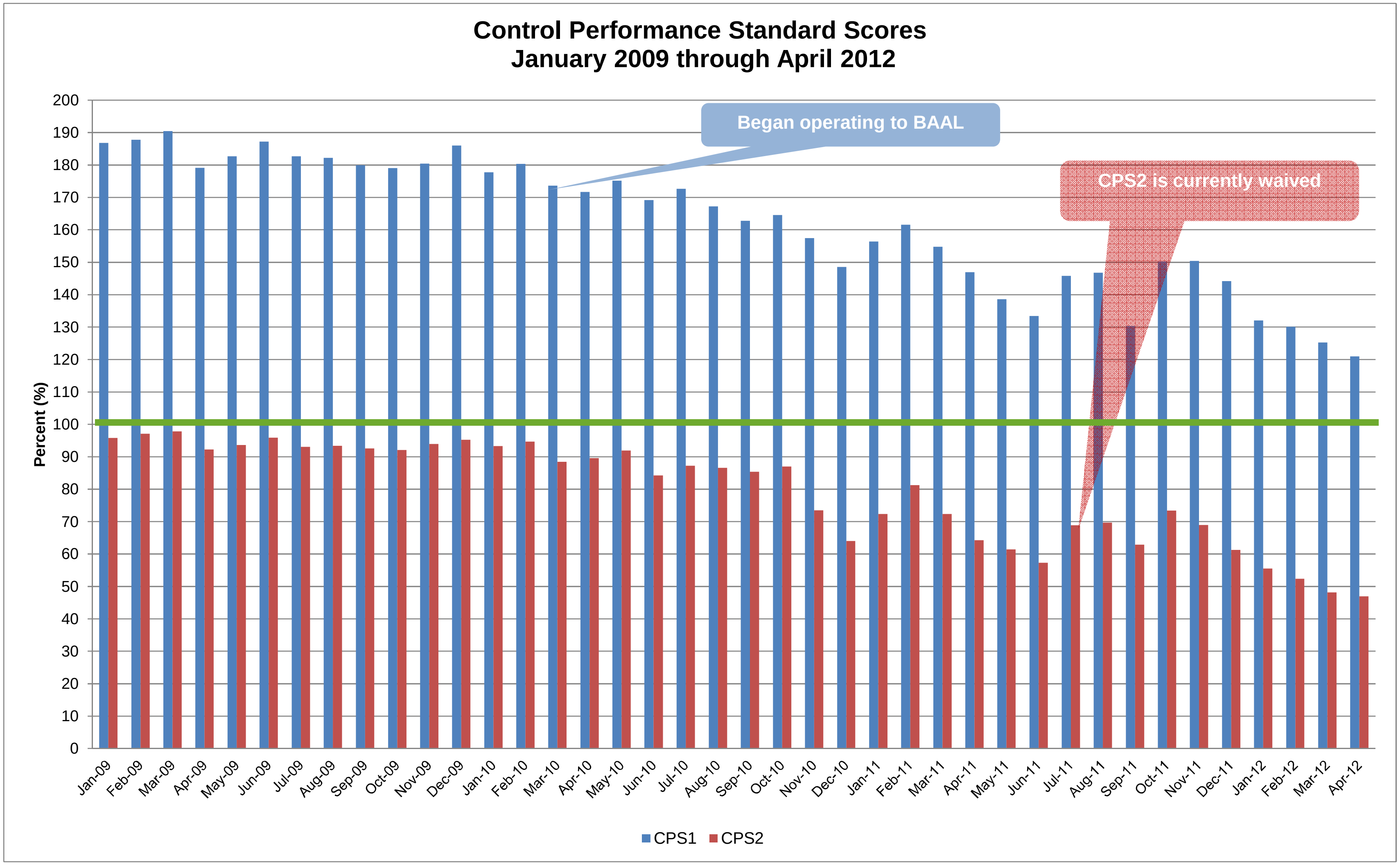
Balancing authority ACE limit (BAAL)

BAAL

- BAAL is designed to replace CPS2
- Control opposes frequency deviation
- BAAL relaxes area regulation needs
- ACE is allowed to be outside BAAL for up to 30 minutes



Control performance standards (CPS1 & CPS2)



Pass is when CPS1 ≥ 100% and CPS2 ≥ 90%

Slide 70

NERC proposed frequency response obligation

	Eastern	Western	ERCOT	HQ	
Starting Frequency	60	60	60	60	Hz
***Target Minimum Frequency**	59.6	59.5	59.3	58.5	Hz
Contingency Protection Criteria	4500	2740	2750	1700	MW
****Base Obligation**	1125	548	229	113	MW/0.1Hz
Interconnection FRO (includes 25% Reliability Margin)	1406	685	286	141	MW/0.1Hz

Balancing Authority Obligation

$$FRO_{BA} = FRO_{Int} \times \frac{\text{Peak Gen}_{BA} + \text{Peak Load}_{BA}}{\text{Peak Gen}_{Int} + \text{Peak Load}_{Int}}$$

2018 Risk of Retirement

Analysis of 2018 high load sensitivity indicated potential for shortage as a result of OTC retirement

	Case Assumptions			Differences	
CPUC-LTPP High Load Scenario	2020 LTPP Assumptions (MW)	2018 Sensitivity (Developed from 2020 Case) (MW)	2018 LTPP Assumptions (MW)	2018 Senstivity-2018 LTPP Assumptions (MW)	2020 LTPP-2018 Senstivity (MW)
Demand					
CAISO Demand Forecast	62,324	62,324	60,754	1,570	-
Incremental Energy Efficiency (EE)	5,688	5,688	4,167	1,521	-
Load Net EE	56,636	56,636	56,587	49	-
Demand Response (DR)	5,145	5,145	5,051	94	-
Demand Side CHP	819	819	655	164	-
Load net (EE, DR, CHP)	50,672	50,672	50,881	(209)	-
Supply (incremental/decremental)					
OTC	19,292	19,292	19,292	-	-
OTC Retirement	12,079	8,099	8,099	-	3,980
OTC Net OTC Retirements	7,213	11,193	11,193	-	(3,980)
RPS Additions (Note 1)	6,049	Note 1 4,118	4,118	-	1,931
Other Additions	2,797	2,797	2,797	-	-
Total Supply Changes	16,059	18,108	18,108	-	(2,049)
Flexibility					
HE15 Load Following Requirements	2,935	2,827	N/A	N/A	108
Upward A/S and load following shortages	Note 3 3,266	2,535	N/A	N/A	731
Need (Note 2)	4,600	Note 2 3,570	N/A	N/A	1,030

Note 1: Renewable production in 2020 scenario was adjusted to reflect expected 2018 RPS capacity

Note 2: The need of in the 2018 senstivity was estimated based on the quantity of shortage observed and 2020 observed shortages and needs (2,535MW x 4,600MW/3,266MW = 3,570MW)

Note 3: 2020 shortages occur both load following and non-spin

Process Update

Where We Have Been

- CAISO has been using PLEXOS to estimate need for new resources to integrate renewables
  - Develop detailed data inputs for hourly production simulation
    - Loads, renewable profiles, etc.
    - Regulation and Load Following Requirements (Step 1)
    - Import capabilities
  - Run PLEXOS to simulate hourly production
  - Log “violation” when resource stack is insufficient to meet load, reserve, regulation and LFU requirements
  - Add resources until no more violations

Where We Are Now

- CAISO is now proposing to supplement our modeling with a different type of analysis to address those factors unrelated to integration need, as a new step in the process
  – Reliability modeling that calculates Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE)
  – PG&E and E3 have been developing models to conduct this analysis
  – CAISO has also developed a stochastic analysis approach that to test simultaneous ramping capability
  – CAISO has not yet decided which model to use in this case

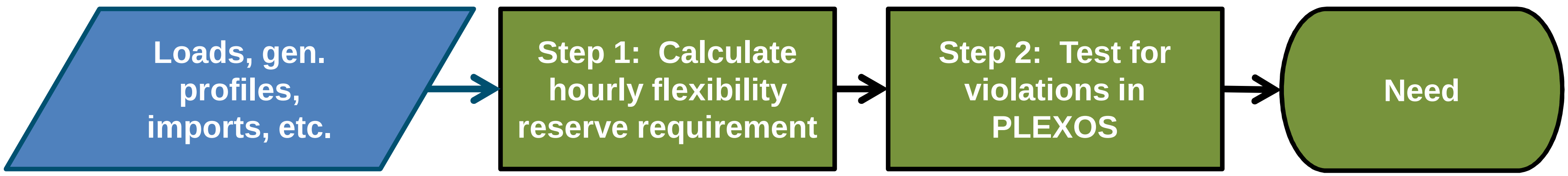
Two Types of Renewable Integration Need

1. Capacity Need:
   – Resources needed to serve load reliably using traditional reliability metrics such as Planning Reserve Margin (PRM) and Loss of Load Expectation (LOLE)

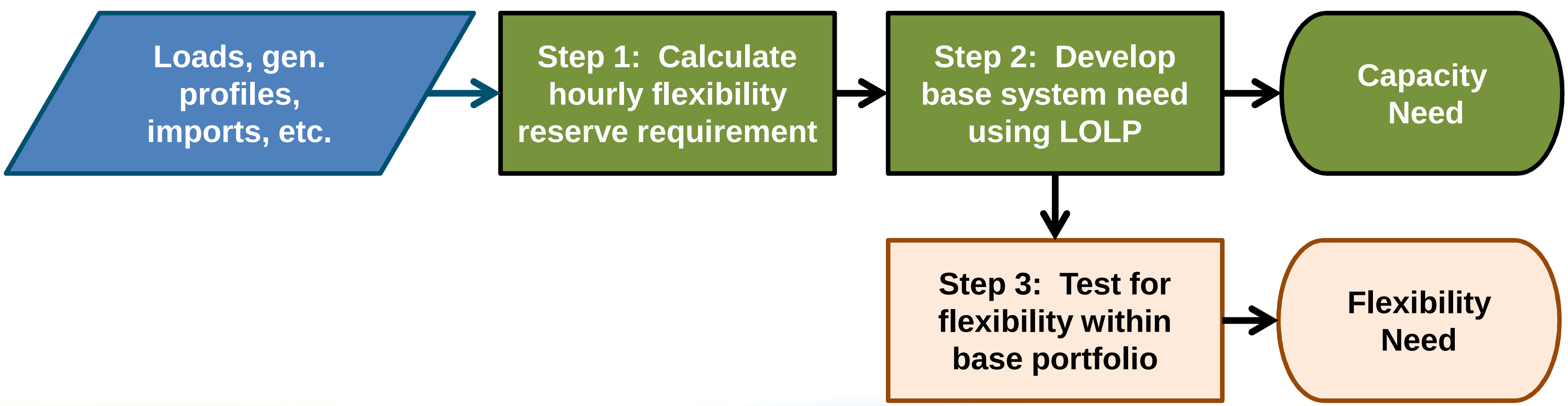
2. Flexibility need:
   – Resources needed to meet 10-minute, 20-minute and hourly ramp requirements

CAISO Proposed New Approach

Previous Methodology



Current Proposal



Step 1 of Proposed New Approach

- Calculate Regulation and Load Following Requirements associated with variability and uncertainty of load, wind and solar for each resource portfolio
- Unchanged from previous approach

Step 2 of Proposed New Approach

- Conduct LOLP modeling to determine need for new capacity to meet a reliability standard of 1-day-in-10-years
  - Calibrate model to reflect 17% PRM under All-Gas Case
  - For each portfolio, calculate change to PRM needed to achieve same reliability as All-Gas Case
    - Expected renewable production will be different from NQC
    - Incremental increase in Reg. and LFU requirements due to renewable penetration
  - Add resources as needed to meet the updated PRM to reflect changes from All-Gas case

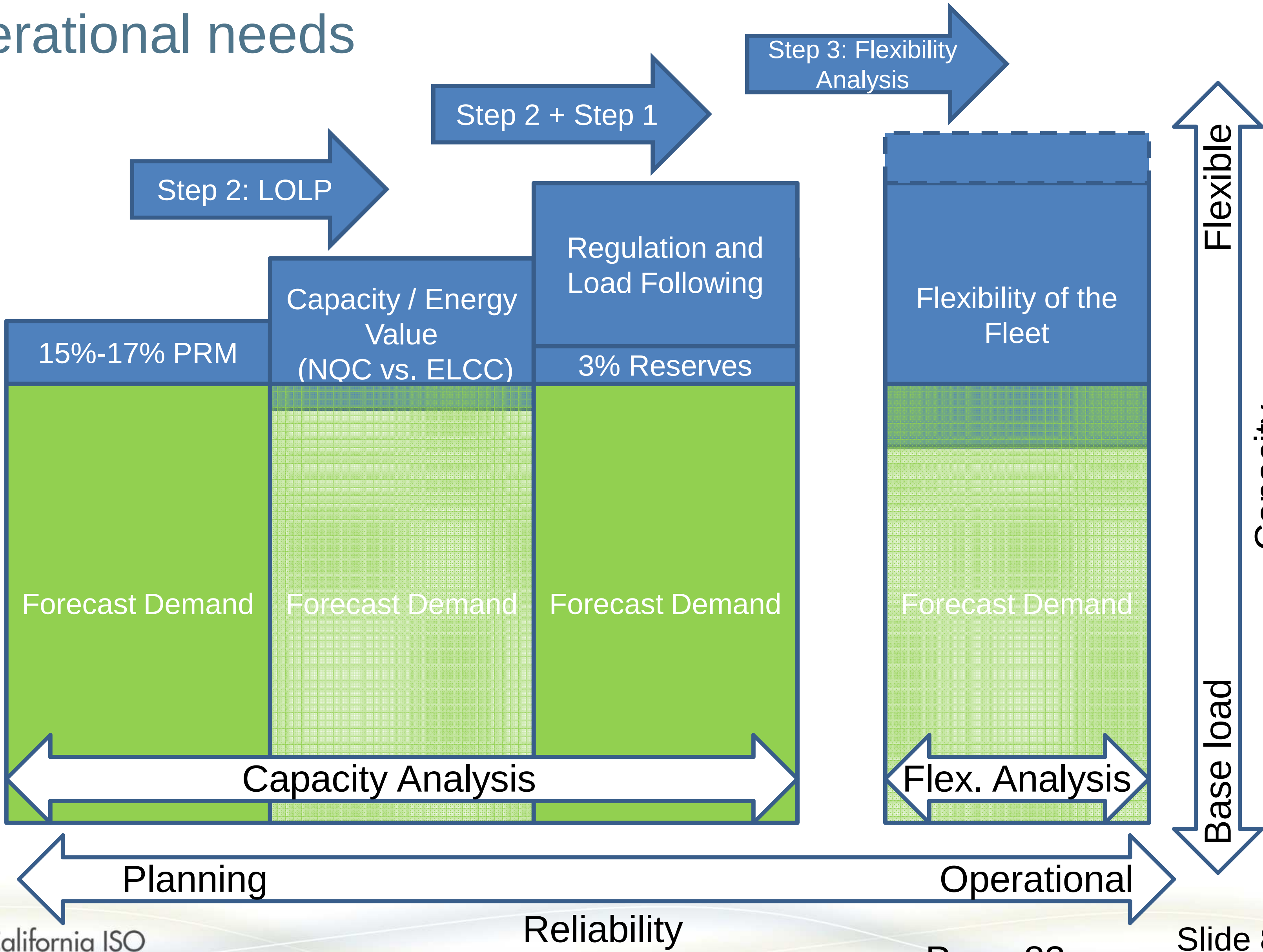
Step 3 of Proposed New Approach

- Test for flexibility within portfolio that comes from Step 2
  - Includes any resources added to meet reliability standard
- Need for ramping capability is not the same thing as need for new resources
  - Conversion of existing resources to something more flexible could solve a ramping problem without changing the PRM
- Stochastic component estimates the probability of having a ramping capacity shortage based on distribution of hourly ramps
  - Within-hour ramps also assessed through incorporation of Step 1 results
- PLEXOS runs to test operability of portfolio that comes from Step 3

Stochastic Simulation

- Purpose
  - To incorporate uncertainties in key input assumptions in determining need for capacity
- Scope
  - May apply to all cases
  - May be used together with Plexos simulation
- Study Approach
  - Probabilistic simulation
  - Loss of Load Probability (LOLP)
  - Assess probability of flexibility shortage

Flexibility needs analysis bridges planning and operational needs



Overview of Stochastic Methodology – E3

Arne Olson
Andrew DeBenedictis
Ryan Jo

Energy+Environmental Economics

Step 2:
E3 ELCC Model

CPUC Workshop

June 4, 2012

Arne Olson, E3

Two Types of Renewable Integration Need

1. **Capacity Need:**
   - Resources needed to serve load reliably using traditional reliability metrics such as Planning Reserve Margin (PRM) and Loss of Load Expectation (LOLE)

2. **Flexibility need:**
   - Resources needed to meet 10-minute, 20-minute and hourly ramp requirements

Step 2: Capacity Need

+ **Capacity need divided into two categories**
  - **Conventional capacity need**: resources needed to achieve a 17% PRM
  - **Capacity need due to renewables:** resources needed above PRM to achieve equivalent reliability as the All-Gas Case Benchmark
+ **Two different tools used to determine need**
  - **Conventional capacity need**: PRM Calculator
  - **Capacity need due to renewables:** E3 ELCC Model

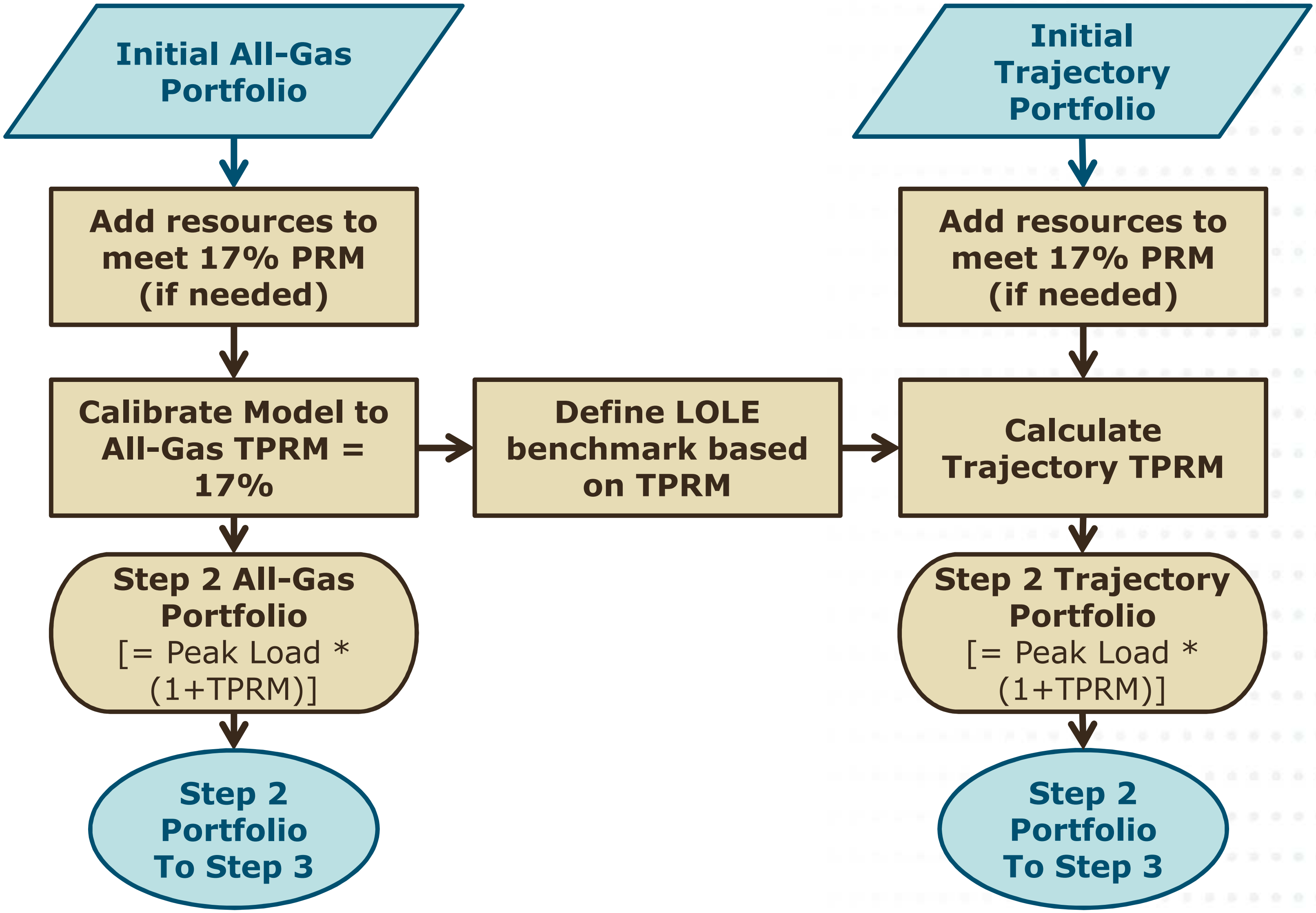
Step 2a: Conventional Capacity Need

- Calculate reserve margin for each scenario
- Add resources until reserve margin = 17%
- Conventional Capacity Need = MW of resources added

Step 2b: Capacity need due to renewables

- **Conduct LOLP modeling to determine need for new capacity to meet a reliability standard of 1-day-in-10-years**
  - Calibrate model to reflect 17% Target PRM (TPRM) under All-Gas Case by adjusting definition of 1-day-in-10 year Loss of Load Expectation
    - Alternate case calibrated to ~25% Target PRM to reflect today's reliability
  - For each portfolio, calculate resources needed above PRM to achieve same reliability as All-Gas Case (if any)
    - Expected renewable production will be different from NQC
    - Incremental increase in Reg. and LFU requirements
  - Add resources to meet PRM plus Above-PRM needs
- **Capacity need due to renewables = MW of resources added**

Step 2 Details



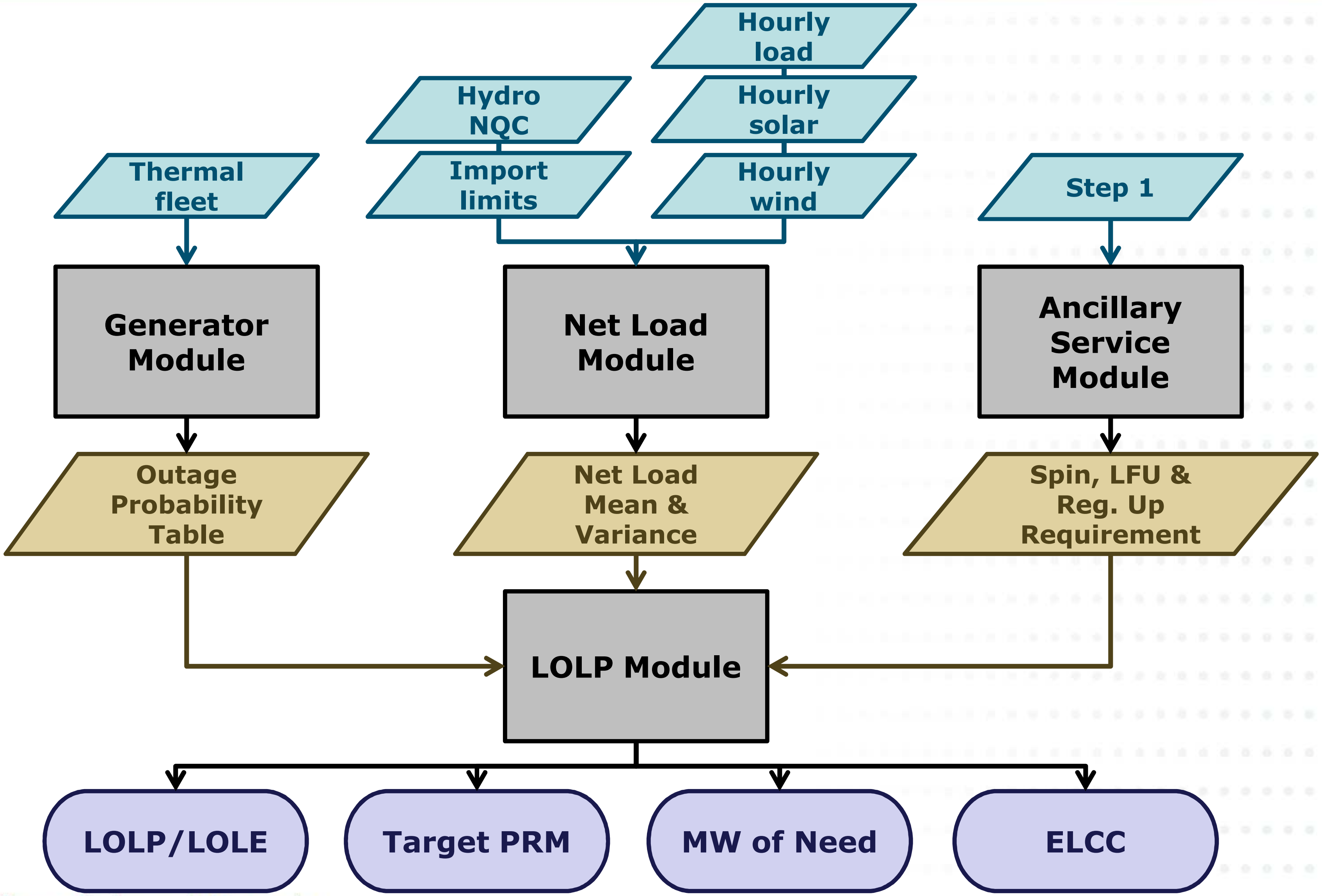
E3 ELCC Model Overview

- **Five-step methodology:**
  - Step 1: calculate generator outage probability table
  - Step 2: calculate hourly net load mean and variance
  - Step 3: add reserve requirements for within-hour variability
  - Step 4: calculate probability that G ≤ L for 8760 hours
  - Step 5: add generation until LOLE = target reliability level
- **Additional useful calculations**
  - Target Planning Reserve Margin (i.e., reserve margin that achieves 1-day-in-10-year reliability)
  - Renewables Effective Load-Carrying Capability (ELCC) at various penetration levels

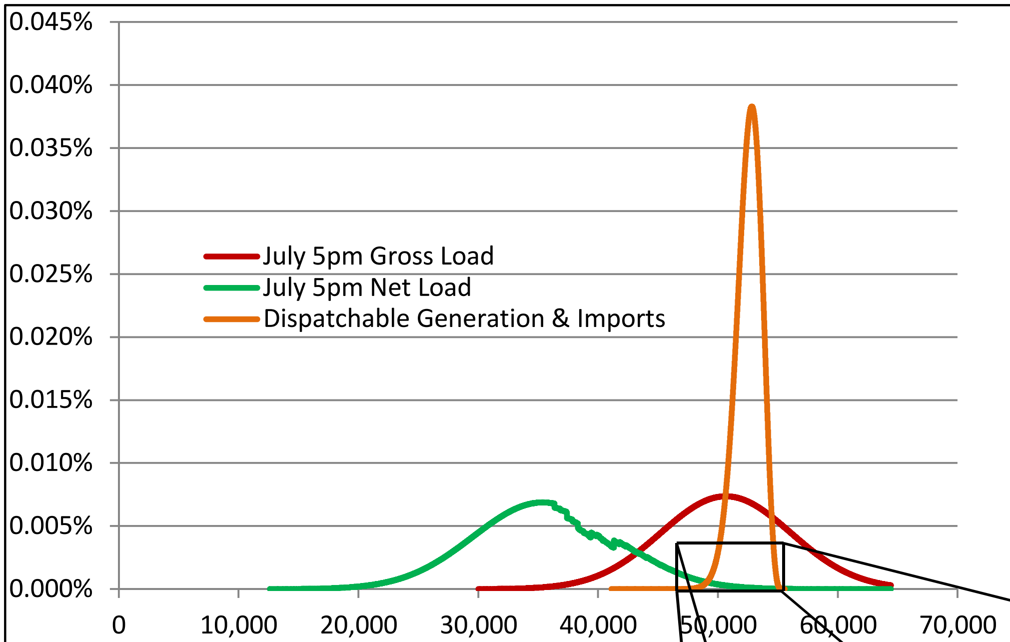
Metric Definition

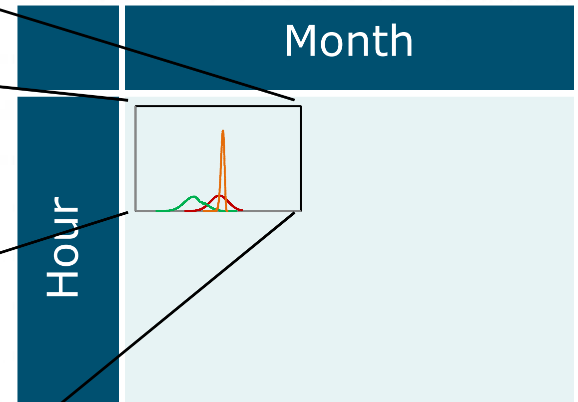
- **Loss of Load Probability (LOLP)** is the probability that load will exceed generation in a given hour
- **Loss of Load Expectation (LOLE)** is total number of hours wherein load exceeds generation. This is calculated as the sum of all hourly LOLP values during a given time period (e.g., a calendar year)
- **Effective Load Carrying Capability (ELCC)** is the additional load met by an incremental generator while maintaining the same level of system reliability
- **Target Planning Reserve Margin (TPRM)** is the planning reserve margin needed to meet a specific reliability standard, e.g., '1 day in 10 years'

E3 ELCC Model Flow Chart

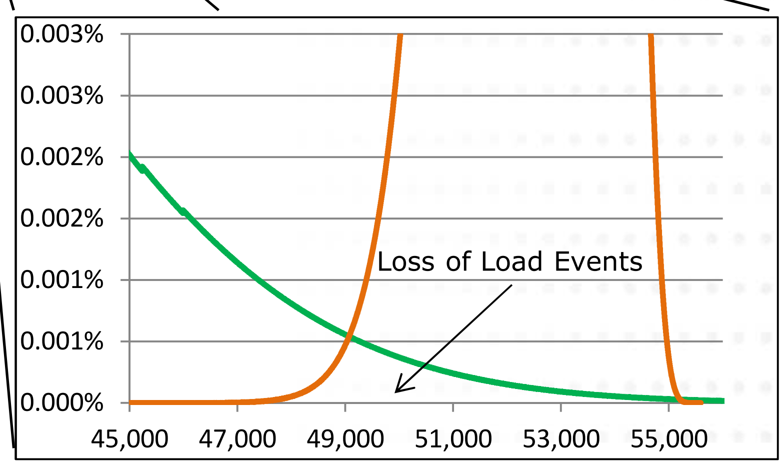


Loss of Load Probability Occurs When Generation < Net Load



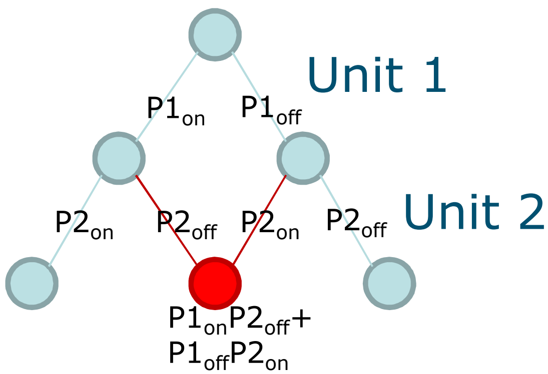


12 x 24 x 2 =
576 Total Distributions



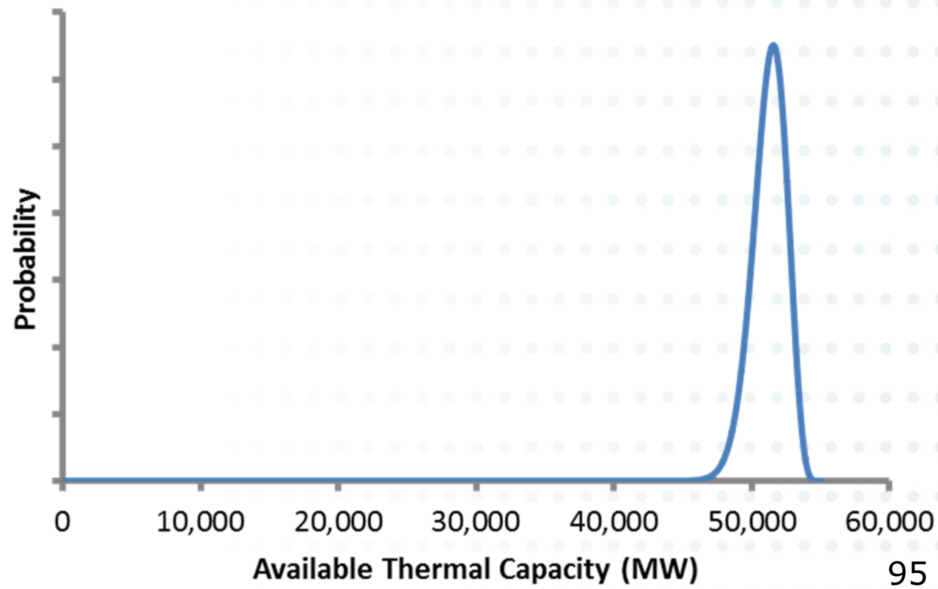
- **The sum of the overlapping areas for all time slices gives the loss of load expectation for the entire year**

Generator Module



Index *i*	*G* (Generation MW available)	*P* (Probability that exactly G MW available)
1 ↓ *I*	0 MW ↓ 55,000 MW	Calculated using outage probability tree

+ **The probability of combinations of thermal unit forced outages are calculated by fully enumerating a binary outage probability tree**



Net Load Module

+ **The net load is gross load minus expected wind and solar output**
  - Gross load is represented by a normal distribution while wind and solar are accurately represented with histograms for each 'hour-month'
  - 1 in 5 loads are mapped to a separate wind histogram to capture wind-load correlation
  - Makes maximum use of all available data
+ **Net load shapes are calculated for 576 annual time periods**
  - 24 x 12 x 2: 24 hours per day, 12 months, 2 day types (workday vs. weekend/holiday)

Data Availability

	Load	Solar PV	Solar Thermal	Wind
1990		X		
1991		X		
1992		X		
1993		X		
1994		X		
1995		X		
1996		X		
1997		X		
1998		X	X	
1999		X	X	
2000		X	X	
2001		X	X	
2002		X	X	
2003	X	X	X	
2004	X	X	X	X
2005	X	X	X	X
2006	X			X
2007	X			
2008	X			
2009	X			
2010	X			

Ancillary Service Module

- **System operator procures reserves to avoid problems within the hour**
- **Three types of reserves:**
  - Contingency reserve: needed to avoid firm load curtailment under Stage 3 emergency
  - Regulation reserve: needed to capture within-hour net load variability
  - Load following up: needed to avoid lost load due to net load forecast errors
- **Model Implementation:**
  - Model assumes 3% of load for spinning reserve
  - Net load is grossed up by the 95th percentile of Step 1 regulation and LFU
    - Multiple other options were explored. The impact on the results of alternative analytical methods was minor while the increase in model complexity was significant. Thus, these methods were not implemented.

LOLP Module

- **LOLP Model compares Net Load levels to generator outage table and calculates reliability metrics**
  - PRM, LOLE, TPRM, ELCC, Need
- **For high renewables cases, need is defined as the *change* in PRM due to renewables for a given reliability level**
  - Calculate TPRM for All-Gas Case first, then look at change in TPRM from addition of renewables while maintaining reliability

Energy+Environmental Economics

Thank You!

Energy and Environmental Economics, Inc. (E3)
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
Tel 415-391-5100
Web http://www.ethree.com

Arne Olson, Partner (arne@ethree.com)
Nick Schlag, Consultant (nick@ethree.com)
Andrew DeBenedictis, Senior Associate (andrew@ethree.com)
Ryan Jones, Associate (ryan.jones@ethree.com)

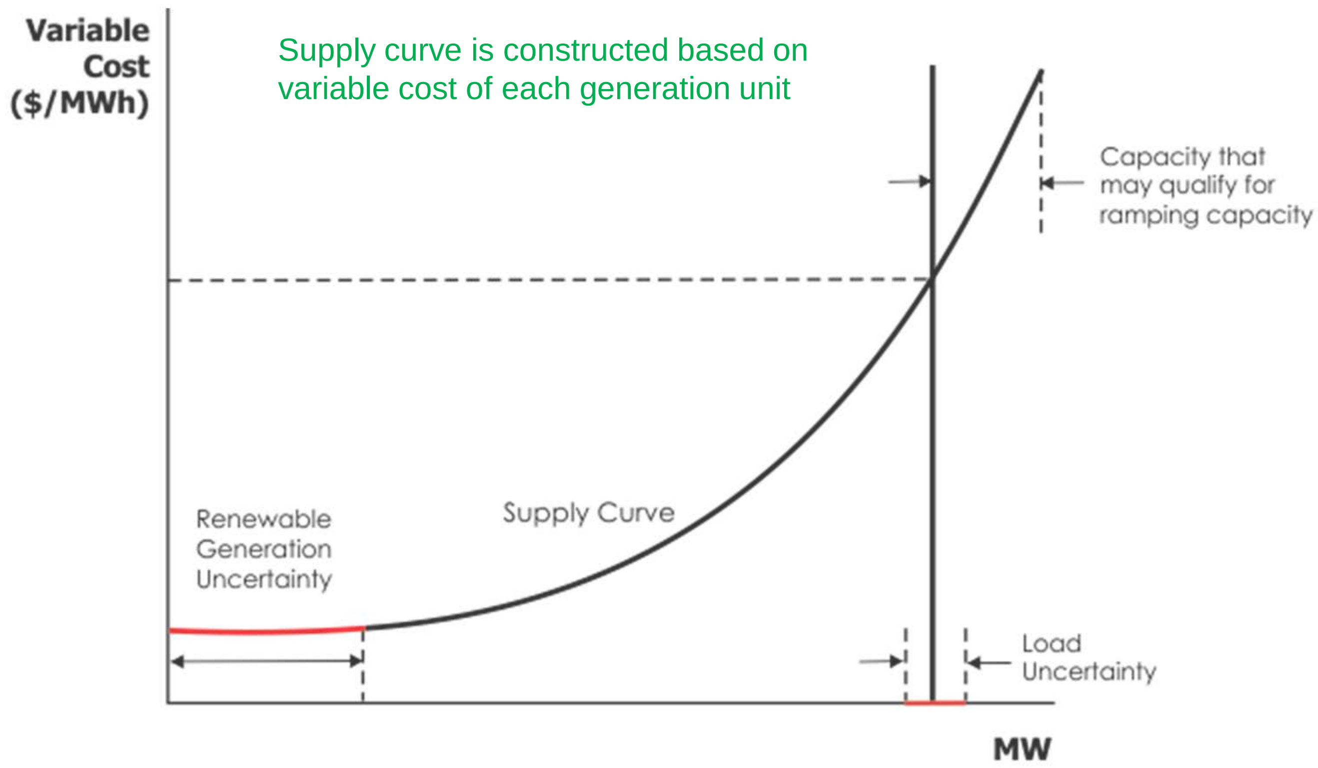
A Stochastic Model for Analyzing Ramping Capacity Sufficiency

Shucheng Liu, Ph.D.
Principal, Market Development

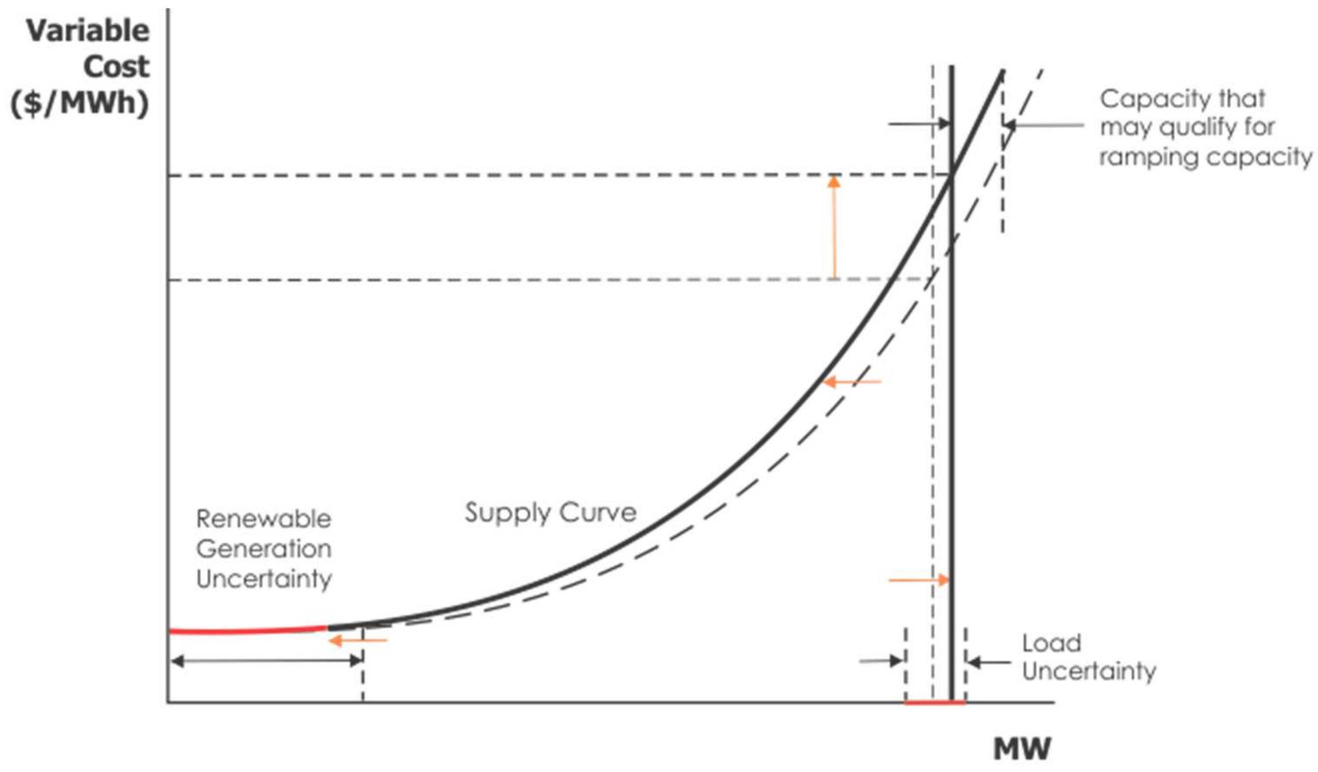
A stochastic model is needed to assess the probability of upward ramping capacity sufficiency.

- A deterministic production simulation case adopts only one of the many possible combinations of input assumptions
- A stochastic model can evaluate various input combinations based on probability distributions and correlations among the stochastic input variables
- Monte Carlo simulation determines the probability of having a ramping capacity shortage
- It complements the deterministic production simulation

Available ramping capacity depends on the balance of supply and demand.



Uncertainties in supply and demand affect availability of ramping capacity.



Available ramping capacity of each generation unit is determined based on the following factors:

- Maximum and minimum capacity
- Unit availability (due to forced and maintenance outages)
- Dispatch level
- Ramp rate
- Ramp time allowed (10 or 20 minutes)

Ramping capacity shortage may occur due to variations in both availability and requirement.

This stochastic model considers uncertainties in some of the key inputs, including:

- Load forecast
- Inter-hour energy ramp
- Requirements for regulation-up and load following-up
- Generation by wind, solar, and hydro resources
- Availability of generation units (due to forced and maintenance outages)

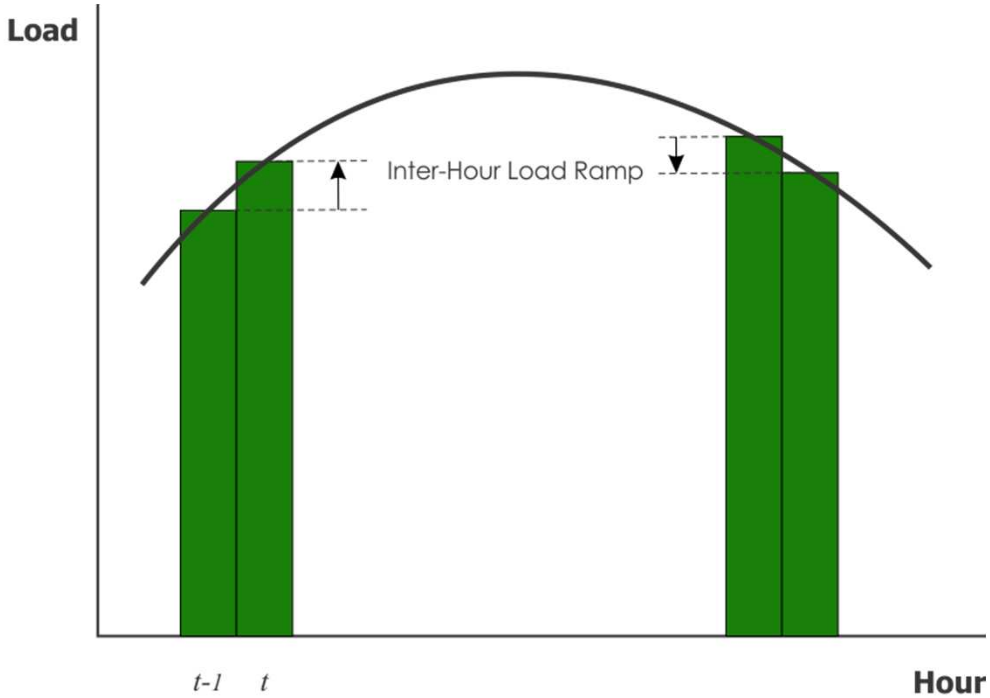
The model is developed for a time period in which all hours have similar conditions.

- No unit commitment
- No chronologic constraint (such as min run time and min down time, etc.)
- Independent with identical probability distribution functions for each hour in the period
- Probability of ramping capacity shortage for each hour determined through Monte Carlo simulations
- Probability of ramping capacity shortage in the whole year calculated based on Binomial distribution

Probability distributions are fitted based on data from the Plexos production simulation model.

- Hourly load forecast
- Hourly inter-hour load ramp
- Hourly regulation and load following-up requirement
- Hourly wind, solar, and hydro generation
- Uniform distribution functions based on generation unit forced and maintenance outage rates

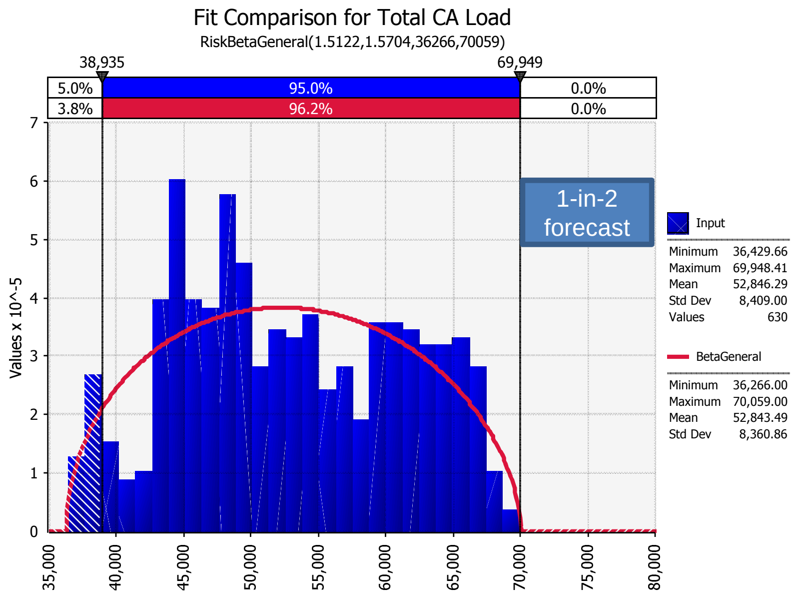
Inter-hour load ramp is calculated based on hourly load forecast.



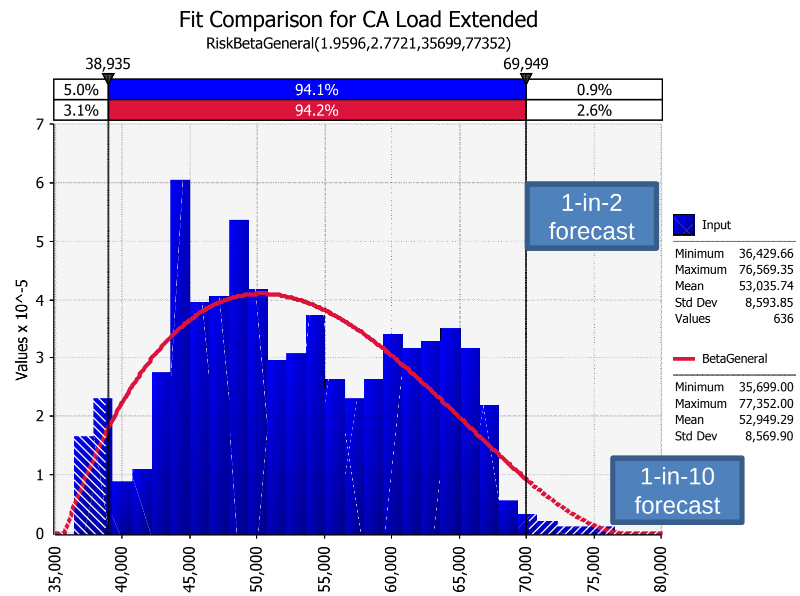
- Upward direction only
- A new stochastic variable
- Met by 60-min ramping capability
- A part of load

$$Inter\text{-}Hour\ Ramp_t = \max(0, Load_t - Load_{t-1})$$

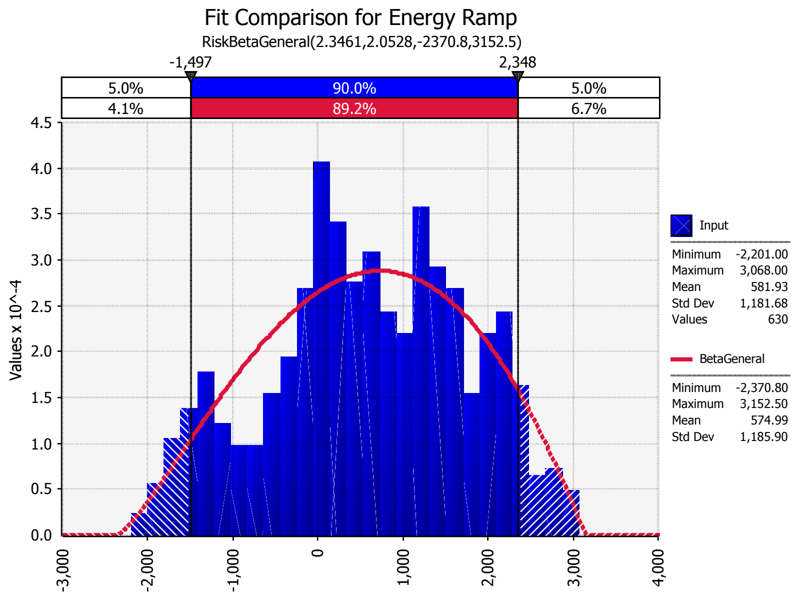
These are examples of the fitted probability distribution functions.

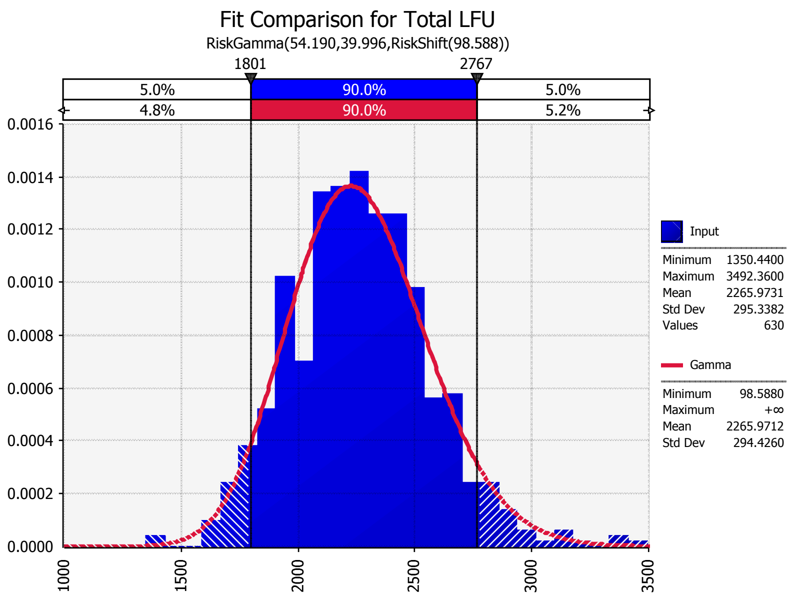


Exploring the probability to have load higher than 1-in-2 forecast

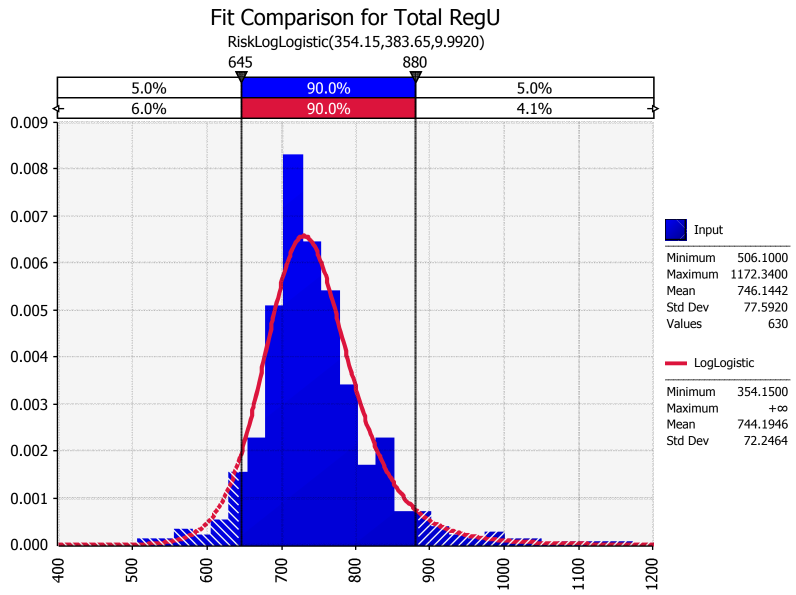


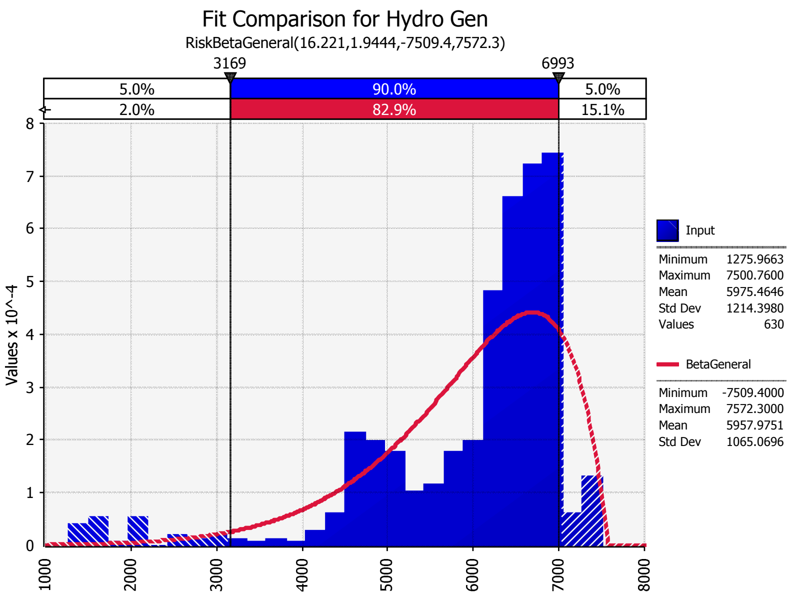
Examples of the fitted probability distribution functions. (cont.)



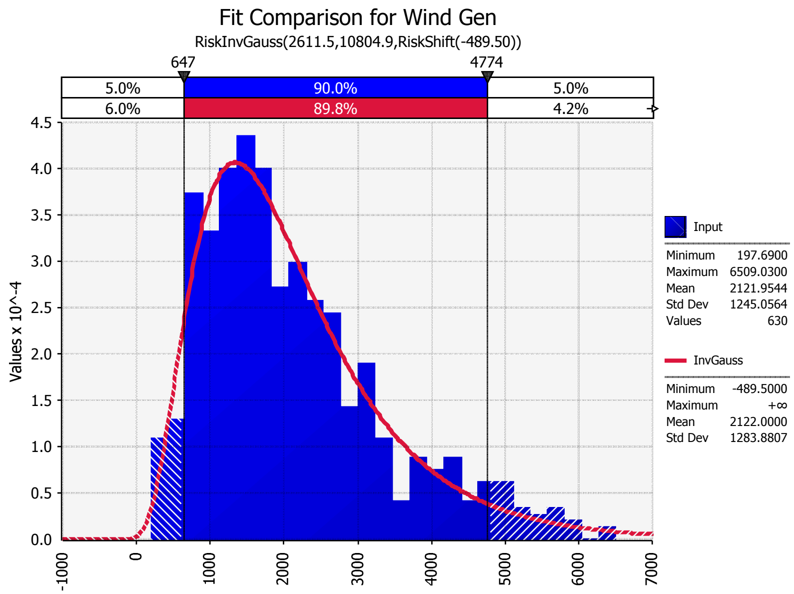


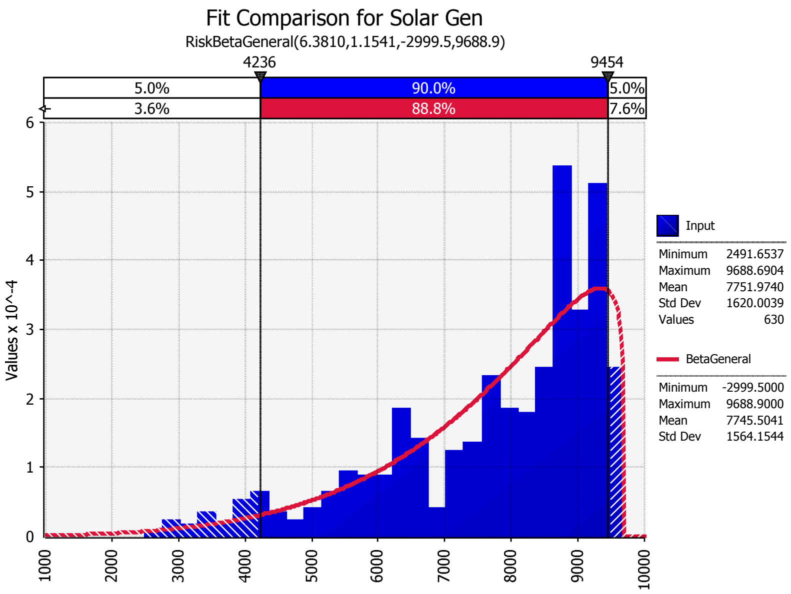
Examples of the fitted probability distribution functions. (cont.)





Examples of the fitted probability distribution functions. (cont.)





Correlations among the stochastic variables are enforced.

	Load	Load Ramp	Wind Gen	Solar Gen	Hydro Gen	RegU	LFU
Load	1	0.2884	-0.0947	-0.1997	0.4302	0.3801	0.0722
Load Ramp	0.2884	1	-0.3782	0.6156	0.0779	0.2064	-0.3193
Wind	-0.0947	-0.3782	1	-0.1618	0.2855	-0.0108	0.0609
Solar	-0.1997	0.6156	-0.1618	1	0.0254	-0.1101	-0.5064
Hydro	0.4302	0.0779	0.2855	0.0254	1	0.3094	-0.1283
RegU	0.3801	0.2064	-0.0108	-0.1101	0.3094	1	0.1415
LFU	0.0722	-0.3193	0.0609	-0.5064	-0.1283	0.1415	1

This is an example of correlation matrix

Generation units in the stochastic model have the following characteristics from the Plexos model.

- From input data
  - Maximum and minimum capacity
  - Ramp rate
  - Forced outage and maintenance outage rates
- From Plexos simulation results
  - Average generation cost (to determine an initial dispatch order)

Generation unit availability is stochastically determined.

- Forced and maintenance outages are determined independently for each generation unit
- Each of the outages is determined based on the unit's outage rate and a draw using a uniform distribution function
- A maintenance outage allocation factor is applied to represent the seasonal pattern of maintenance
- The unit is unavailable when any one of the outages occurs

Contributions of a generation unit to meet energy and ramping capacity requirements are subject to:

- 10-min upward ramping capacity constraint

$$AS_i \le \min(10 \times RampRate_i, MaxCap_i - MinCap_i)$$

- 20-min upward ramping capacity constraint

$$AS_i + LFU_i \le \min(20 \times RampRate_i, MaxCap_i - MinCap_i)$$

- 60-min upward ramping capacity constraint

$$AS_i + LFU_i + LdRamp_i \le \min(60 \times RampRate_i, MaxCap_i - MinCap_i)$$

- Maximum capacity constraint

$$E_i + AS_i + LFU_i + LdRamp_i \le MaxCap_i$$

E_i – energy dispatch	AS_i – upward ancillary service contribution
LFU_i – load following up contribution	$LdRamp_i$ – inter – hourloadrampcontribution

California ISO
Shaping a Renewed Future

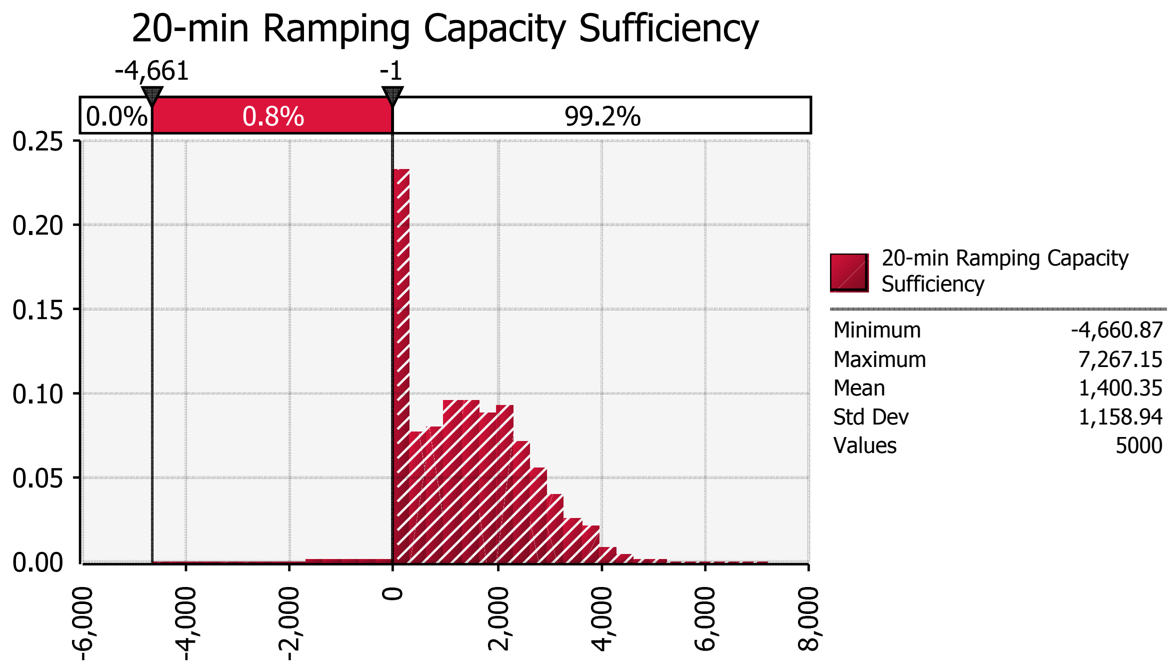
The model seeks a least-cost solution to meet energy and all ramping capacity requirements.

- Generation units are dispatched economically to meet load first
- Remaining qualified ramping capacity is used to meet upward ancillary service, load following, and inter-hour load ramp requirements
- Dispatch and ramping capacity are co-optimized when there is a ramping capacity shortage initially

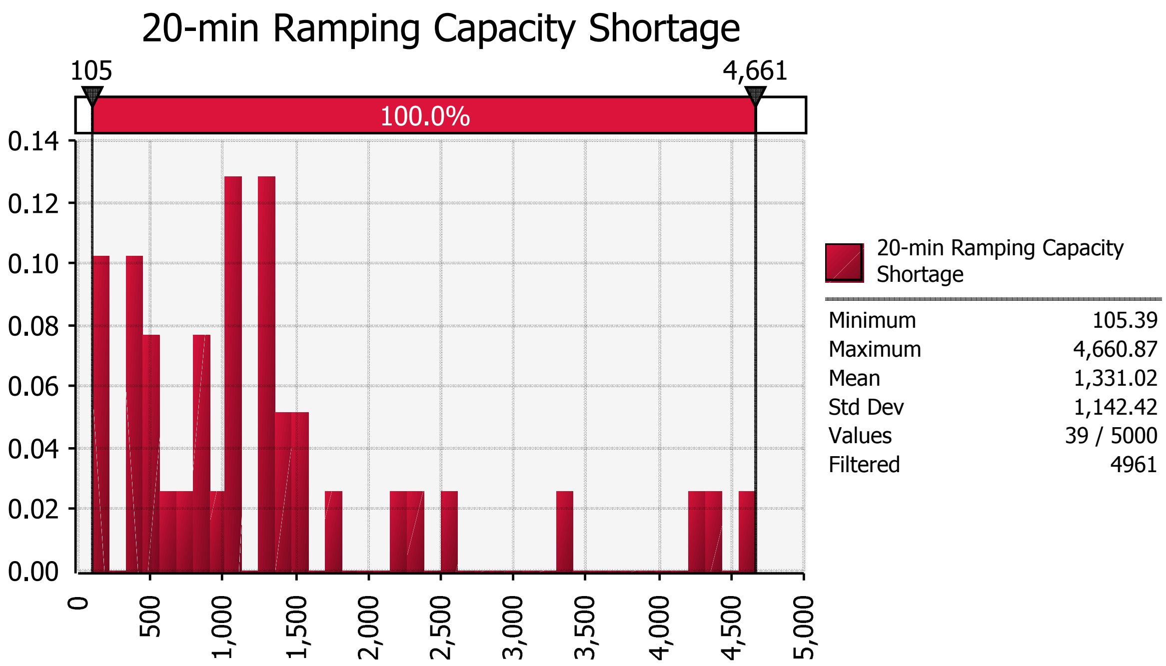
Monte Carlo simulation produces probabilistic results.

- Monte Carlo simulation is conducted using this stochastic model
- The simulation results are presented in a probability distribution format
- The key results are the probability to have ramping capacity shortage each hour and the probabilistic distribution of the volume of the shortages

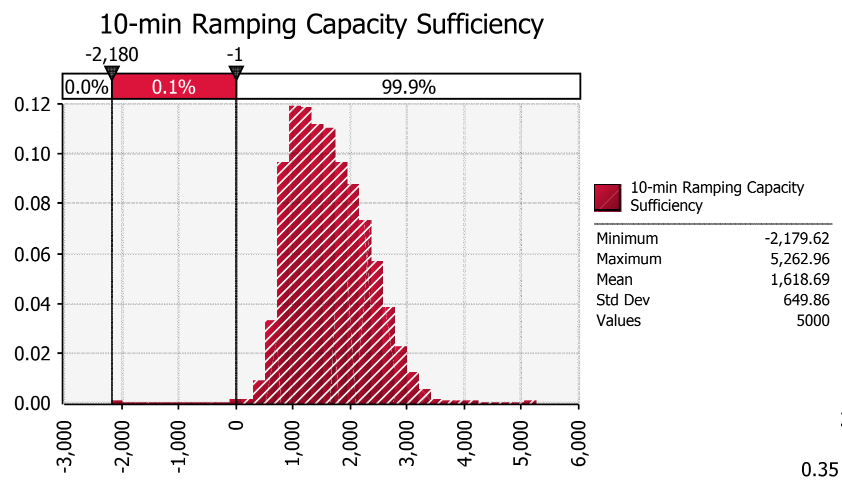
This example has a 0.8% probability to have 20-min ramping capacity shortage each hour.

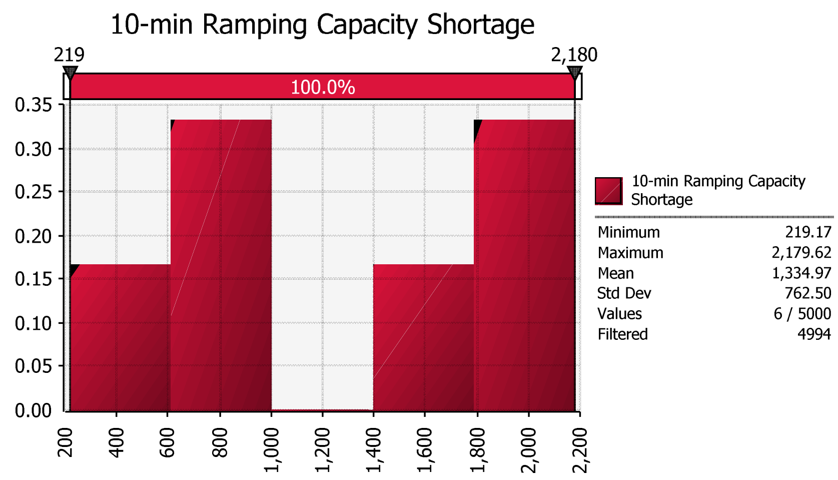


The highest 20-min ramping capacity shortage is 4,661 MW in this example.



The probability to have 10-min ramping capacity shortage each hour is 0.1%.





The Monte Carlo simulation results for all periods are summarized as follows:

	Example Case			
	Super-Peak		Summer Off-Peak	
	10-min	20-min	10-min	20-min
# of Hours in the Period	630	630	2298	2298
Probability of Shortage	0.12%	0.78%	0.04%	0.16%
Max Shortage (MW)	2,180	4,661	1,420	3,855

The cumulative probabilities of ramping capacity shortage are calculated using Binomial distribution.

	Example Case	
i	10-min	20-min
1	81.3%	100.0%
2	49.9%	99.8%
3	23.6%	99.1%
4	8.9%	97.2%
5	2.8%	93.0%
6	0.7%	85.8%
7	0.2%	75.4%
8	0.0%	62.7%
9	0.0%	49.0%
10	0.0%	35.9%
11	0.0%	24.6%
12	0.0%	15.9%
13	0.0%	9.6%
14	0.0%	5.5%
15	0.0%	2.9%
16	0.0%	1.5%
17	0.0%	0.7%
18	0.0%	0.3%
19	0.0%	0.1%
20	0.0%	0.1%
21	0.0%	0.0%
22	0.0%	0.0%

It is the probability to have at least i hours with ramping capacity shortage in year 2020.

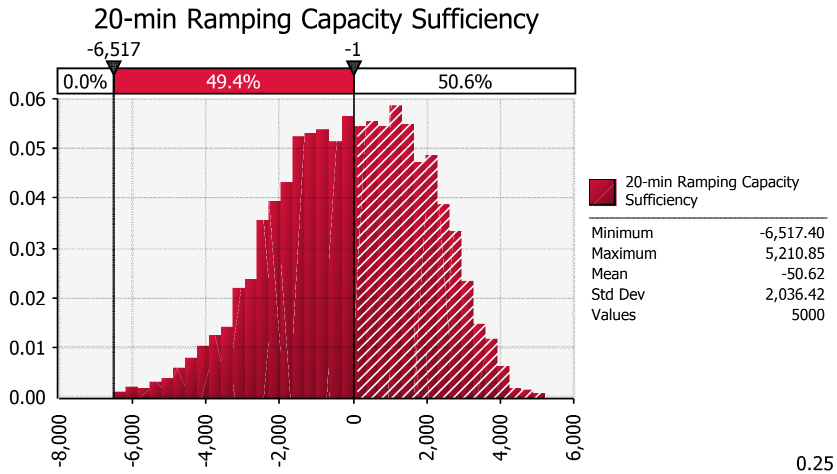
Expected number of hours with ramping capacity shortage in 2020 are calculated based on the probabilities.

Example Case	
10-min	20-min
1.68	8.59

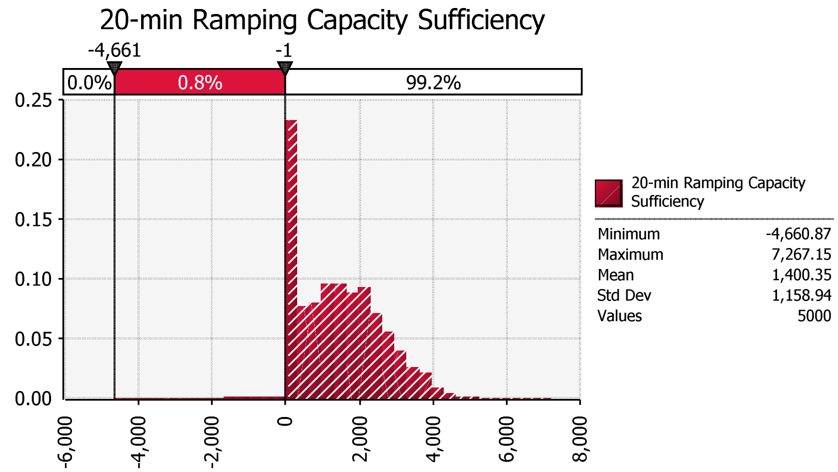
Co-optimization re-dispatches resources to free up more flexible resources when needed.

- In each iteration generation units are first dispatched based on capacity stacked up by cost
- Ramping capacity from remaining units is used to meet all upward ramping capacity requirements
- Dispatch and ramping capacity are co-optimized when there is a ramping capacity shortage initially
- Co-optimization finds a least-cost solution to meet requirements for energy and all upward ramping capacity
- Shortage occurs in ramping capacity when supply is insufficient

Probability of ramping capacity shortage is much lower with co-optimization in the Monte Carlo simulation.



Left – High-Load case Super-Peak period without co-optimization



Right – with co-optimization in simulation

Commercial software is used to develop the model and conduct Monte Carlo simulations.

Palisade Decision Tools Suite

http://www.palisade.com/

Frontline Risk Solver Platform for Excel

http://solver.com/platform/risk-solver-platform.htm

Next Steps: Test operational robustness of underlying assumptions

- Assess alternatives for meeting residual needs
- Test underlying assumptions regarding
- Perform additional analysis testing robustness of assumptions
  - Demand Response
  - Energy Efficiency
  - Load forecast
  - Outage / Maintenance rates
  - Import / Export limitations
  - Renewable online schedule

Next Steps: Develop method for studying alternative to meeting needs

- Purpose:
  - Determine if shortages can be resolved using energy or ramping capability.
    - Additional energy may free up flexible resource capability
    - If insufficient ramping, then ramping may be needed
  - After consideration of local resources, if residual shortage needs are identified test different solutions for meeting residual needs:

Ramping Solutions	Energy Solutions
Peaker	Peaker
CCGT (40%-60% of Capability)	CCGT
Storage	Additional demand response
Dispatchable dynamic import	Energy Efficiency
Hydro (not run of river, not in spill)	Imports
Other ramping technologies	Other ramping solutions

  - Assess feasibility of alternative solutions
  - Leverage EPRI/NREL work to the extent possible

Additional Assumptions for Operating Flexibility Analysis

June 4, 2012 LTPP Track 2 Workshop

Contents

- Study year (which year or years to study?)
- Weather Uncertainty
- Flexibility Requirements
- Flexibility Metrics and Targets
- Imports/Exports

Weather uncertainty

- **Why consider weather uncertainty?**
  - To test the system's adequacy to meet the desired reliability target (e.g., outages occur $\leq$1 day in 10 years)
  - Past studies considered normal weather year (2005) only
  - Stochastic approach tests system adequacy under different weather years
- **How to represent weather uncertainty?**
  - At least three weather years with associated probabilities
  - Different load/wind/solar profiles for different weather years
    - Use historical profiles if possible; otherwise simulated profiles
  - Consider estimating regulation and load following requirements for different weather years
  - Estimate resource need to meet reliability target by weather year

PG&E

Flexibility requirements

- **Flexibility requirements cover variability and forecast uncertainty of load/wind/solar for different time intervals corresponding to commitment/dispatch decisions**
  - Regulation requirements: 5-10 minutes forecast window (AGC)
  - Load following requirements: one hour forecast window (intra-hour)
  - Long-start resource commitment: several hours window (day-ahead or intra-day)
- **Forecast error assumptions** (Summer 2020 Standard deviation, MW or % of installed capacity
  - Load: 1002 MW (current assumption)
  - Wind: Historic 8.9% (2010 PIRP); Study range: 2.3% to 7.1% (3.8% current assumption)
  - Solar Thermal*: Historic not available; Study range: 8.7% to 13.8% (10.9% current)
  - Large PV*: Historic not available; Study range: 5.5% to 8.3% (6.9% current assumption)
- **Forecast window assumption**
  - Current load following requirement assumptions cover hour ahead uncertainty only
  - Additional load following or unit comment is needed to cover deviations over the time needed for long-start unit (e.g., a typical combined cycle unit requires 4-5 hours for cold start)
- **Representation of regulation and load forecast requirements**
  - Deterministic 95% highest values
  - Deterministic hourly values
  - Stochastic values

* For 0.2 to 0.5 clearness index.

Current reliability metrics and targets

- **Current electric supply metrics and targets are based on traditional reliability concepts, and do not address flexibility**
- **Assumptions needed to operationalize traditional reliability metrics/target:**
  - Interpretation of 1 day in 10 LOLE reliability target
    - A day with ≥ 1 hours of curtailment
    - A day with ≥ 8 hours of curtailment
    - 24 hours of curtailment
  - Minimum operating reserves before curtailing firm load
    - Stage 3 (rolling curtailments) occur when operating reserves ≤ 3%
    - Should the Stage 3 threshold increase with increased reliance on intermittent resources to provide a flexible capacity margin?

	Metrics	Target
Reliability metrics/target	**Loss of load expectation** (LOLE or probability of outages)	**1 day in 10 year LOLE, or expected outage**
Planning metrics/target	**Planning Reserve Margin (PRM)** (Margin above 1-in-2 peak, expressed as % of peak)	**15% to 17% PRM**

* A metric is a unit of measurement.
* A target is a guideline or a requirement.

Flexibility metrics and targets

- **New flexibility metrics and targets are needed**
- **Assumptions need to be made about how much of the variability and forecast error or deviations should be covered by regulation and load following requirements**
  - NERC's Control Performance Standard 2 (CPS2) requires balancing authorities to maintain its 10 minute average area control error (ACE) within a certain band (~120 MW for CAISO) at least 90% of the time
  - Balancing authorities like BPA plan on 99% compliance to ensure they can meet the 90% minimum CPS2 requirement

	Metrics	Target
Reliability metrics/target	**Loss of load expectation** (LOLE or probability of outages)	**1 day in 10 year LOLE, or expected outage**
Planning metrics/target	**Planning Reserve Margin (PRM)** (Margin above 1-in-2 peak, expressed as % of peak)	**15% to 17% PRM**
Flexibility metrics/target	**Possible metric: Coverage of net load forecast deviation** (% of forecast deviation covered by available flexible capacity)	**Possible target: 90%-99%**

PG&E

Imports/Exports

- **Imports can contribute to meet CAISO's reliability needs if transfer capacity and excess resources are available in neighboring areas**
  - Currently, the CAISO depends on about 10,000 MW of imports
  - 2010 LTPP standard assumptions used 17,000 MW of imports NQC. CAISO limited imports to ~ 13,000 MW in prior integration studies
- **Exports can also help manage over-generation conditions in neighboring areas have excess downward flexibility**
  - Past integration studies showed no over-generation because of assumed neighboring area's flexibility. This may not be realistic given today CAISO experiences over-generation
  - CAISO is working to improve the representation of neighboring systems for renewable integration studies

Next steps

- Propose ranges for additional assumptions used in renewable integration studies
- Incorporate additional assumptions into 2012 LTPP standard planning assumptions and scenarios for Track 2

Conclusion

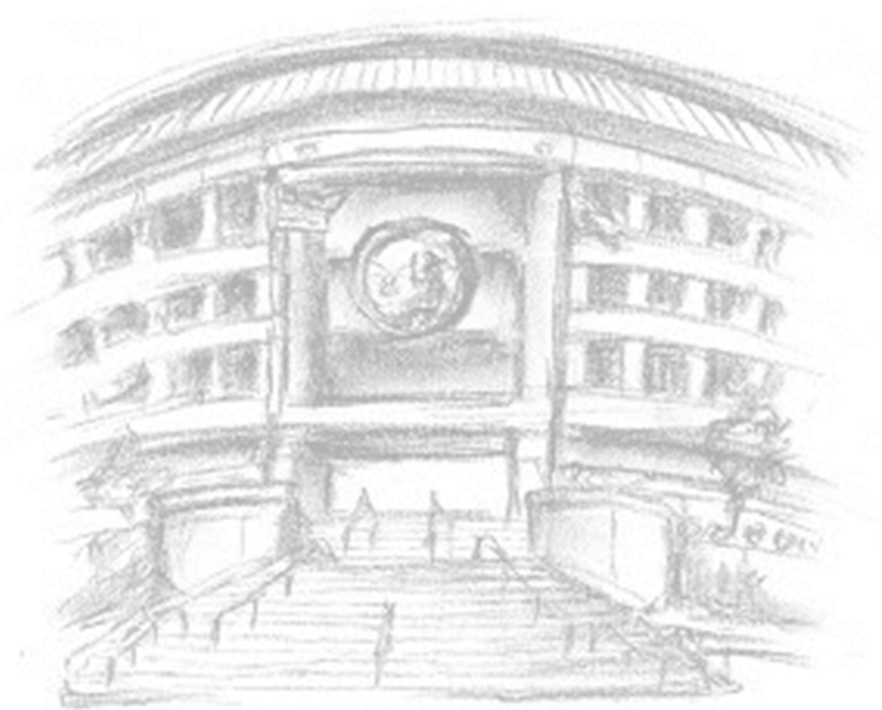
Next Steps

Thank you!
For Additional Information:

www.cpuc.ca.gov

www.GoSolarCalifornia.ca.gov

www.CalPhoneInfo.com



Appendix
Other Supporting Material

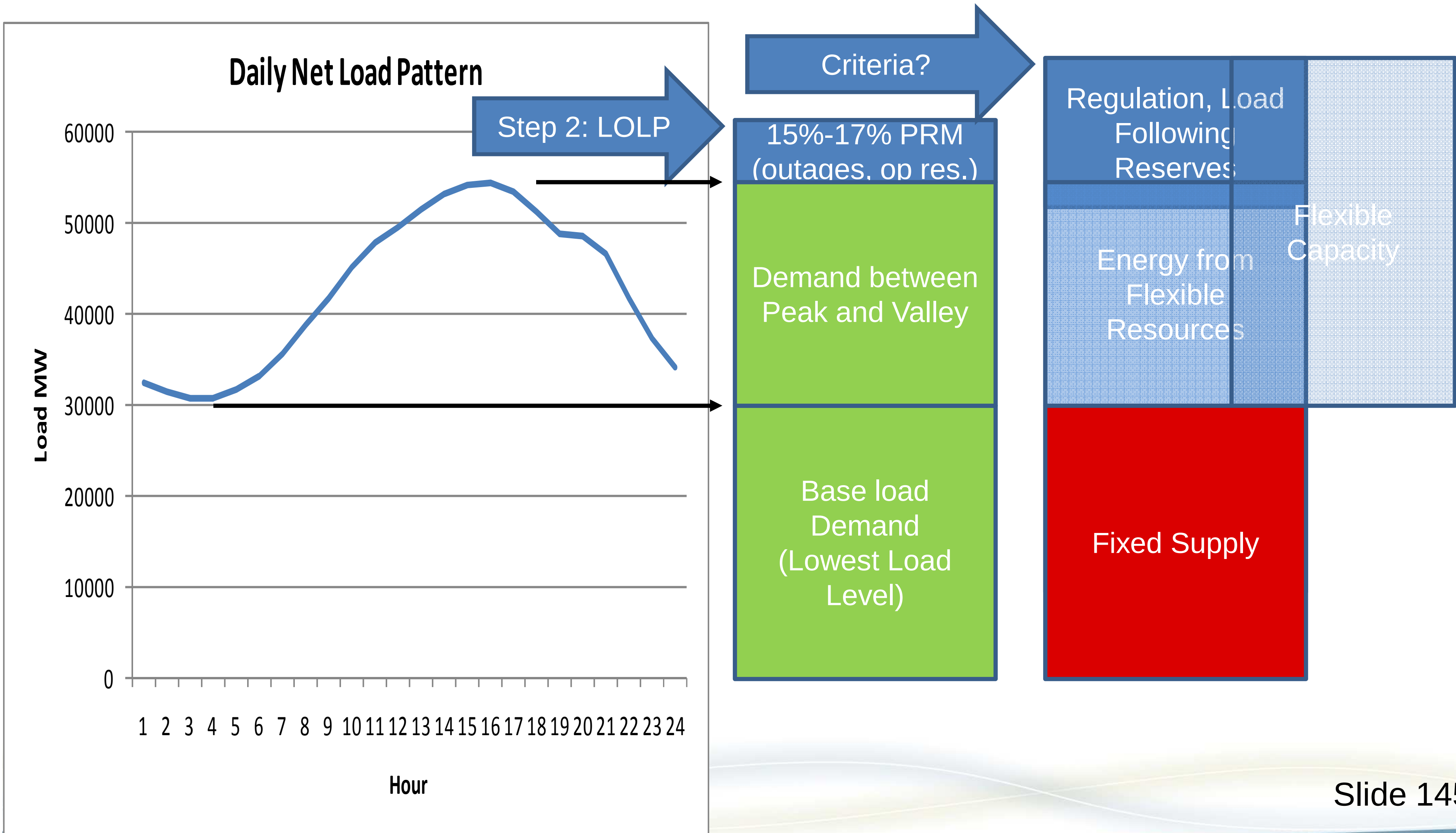
Environment Constrained Case California Load and Resource Balance (July 22, 2020)

	H13	H14	H15	H16	H17
Demand (MW)					
Load	60,547	62,908	63,755	63,486	61,583
Upward AS	4,306	4,494	4,555	4,489	4,479
LFU	2,155	1,993	2,101	2,012	1,929
Total	67,008	69,396	70,412	69,987	67,991
Supply (MW)					
Import	8,143	10,614	11,085	12,560	12,921
Generation	52,404	52,294	52,670	50,926	48,622
Upward AS	4,306	4,494	4,555	4,489	4,479
LFU	2,155	1,993	2,101	2,012	1,929
Total	67,008	69,396	70,412	69,987	67,991
Shortage (MW)					
LFU	0	0	0	0	0
Outage (MW)	4,820	4,500	5,093	4,906	4,641

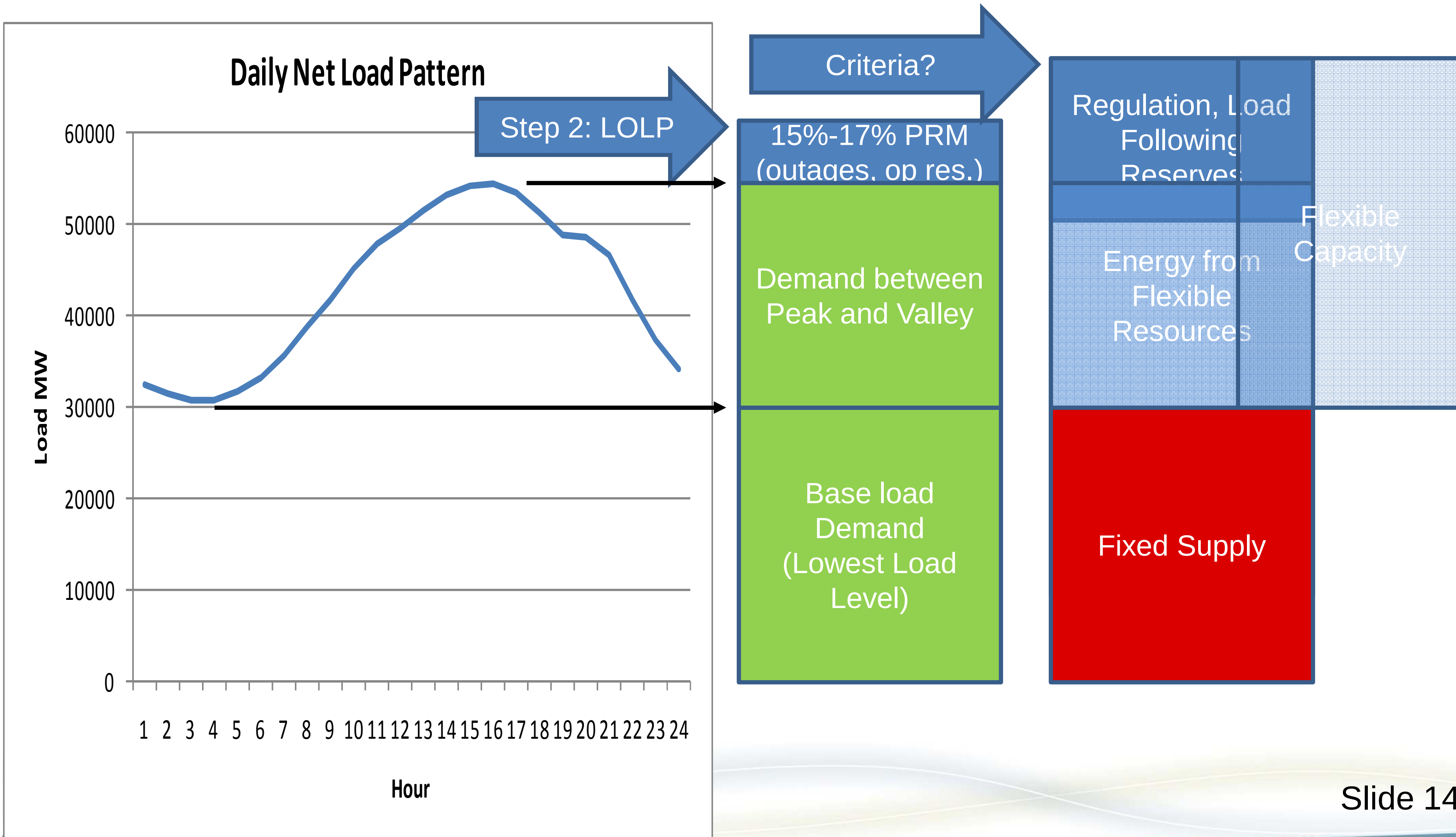
All-Gas Case California Load and Resource Balance (July 22, 2020)

	H13	H14	H15	H16	H17
Demand (MW)					
Load	60,389	62,744	63,589	63,321	61,422
Upward AS	4,313	4,463	4,442	4,562	4,414
LFU	1,934	2,134	1,880	1,798	2,100
Total	66,636	69,341	69,911	69,681	67,937
Supply (MW)					
Import	14,677	14,886	14,886	14,886	14,886
Generation	45,712	47,858	48,703	48,435	46,536
Upward AS	4,313	4,463	4,442	4,562	4,414
LFU	1,934	823	817	838	1,813
Total	66,636	68,031	68,848	68,721	67,650
Shortage (MW)					
LFU	0	1,311	1,063	961	287
Outage (MW)	4,820	4,500	5,093	4,906	4,641

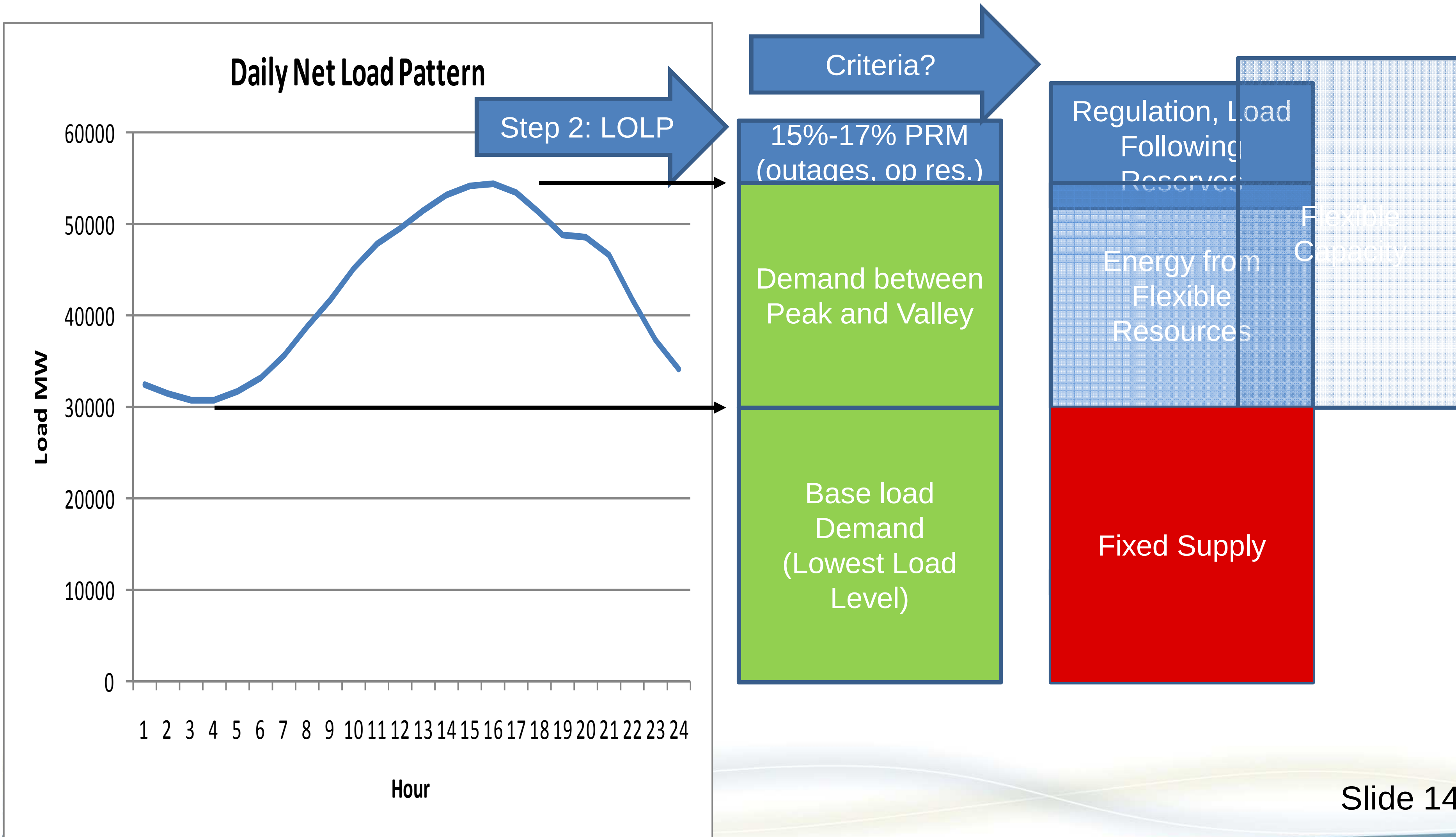
Fleet flexibility serves demand in variety of ways. Flexible capacity may provide reserve or energy.



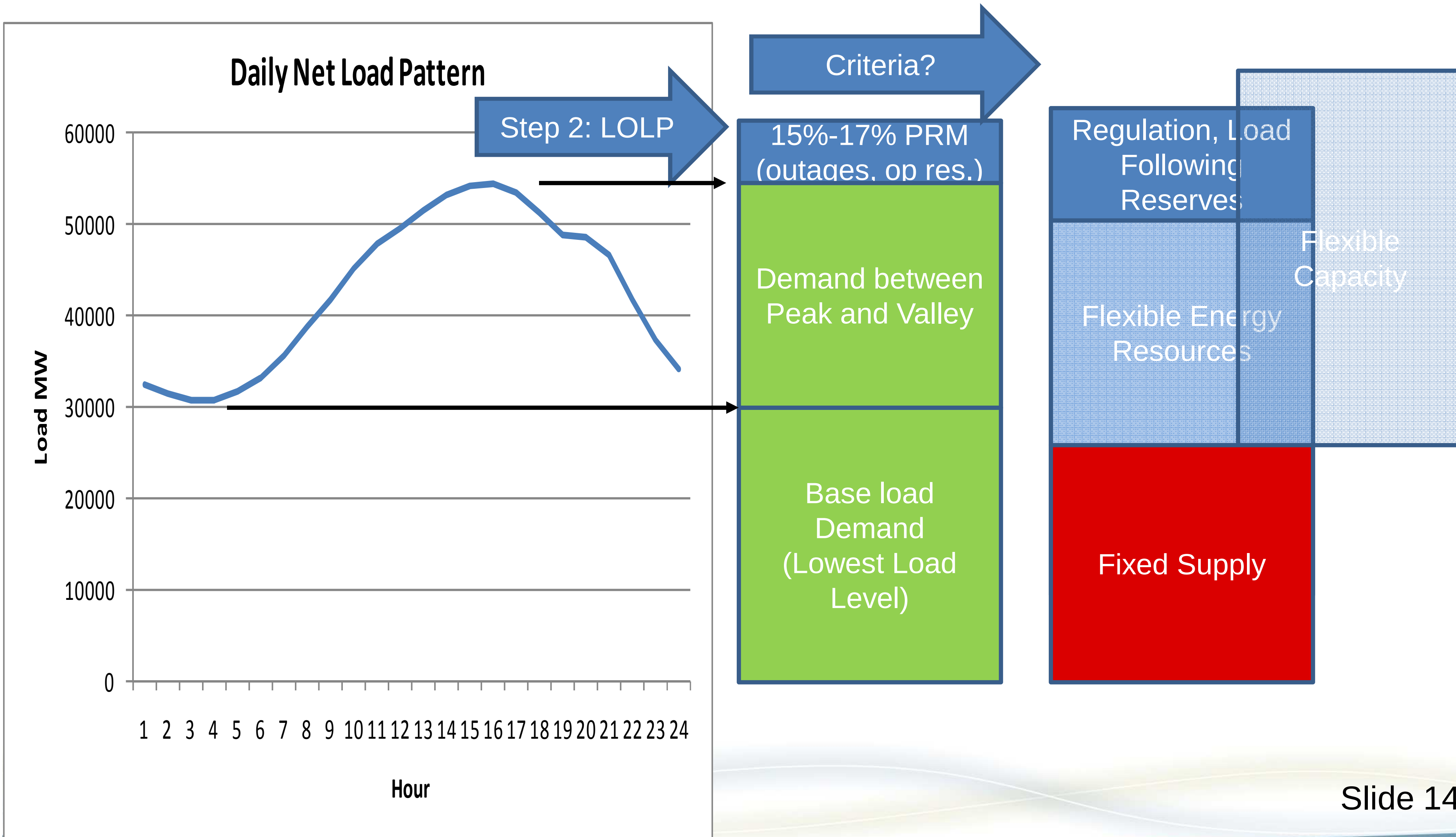
If variable supply under-delivers, flexible capacity will need to produce energy to balance the system.



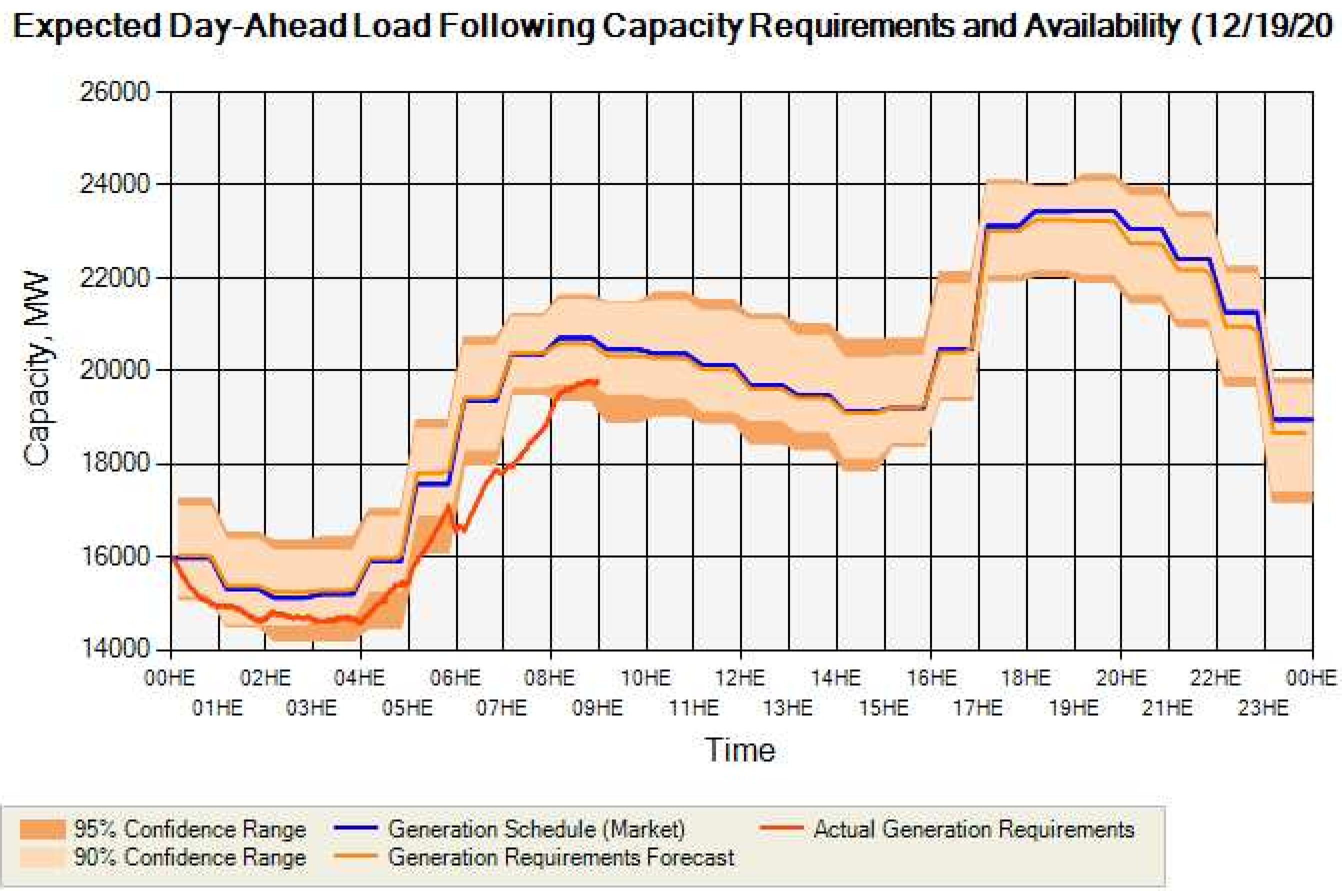
If general capacity constrained then additional energy from any resource can unload needed flexible capacity



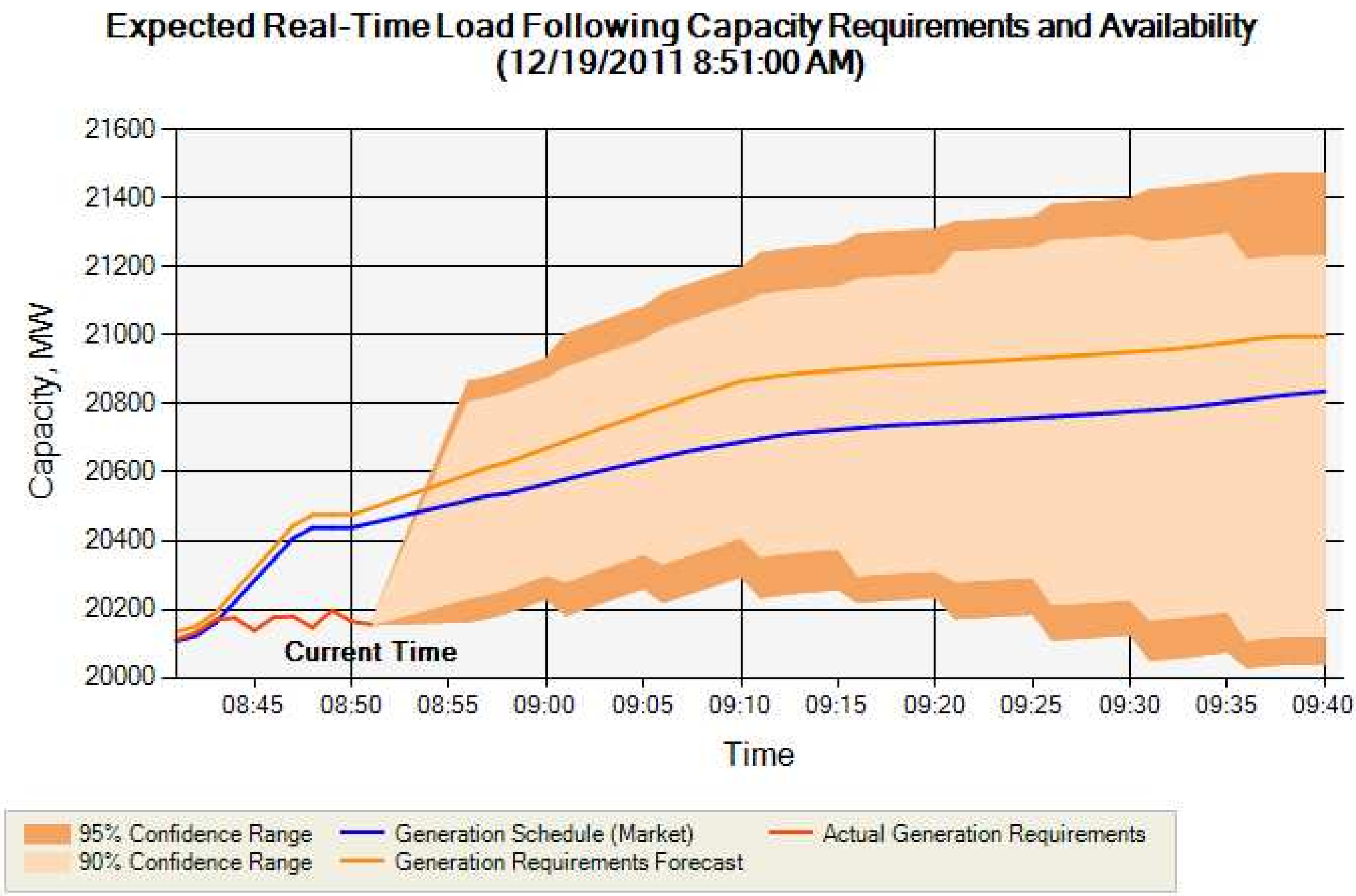
If there is insufficient flexible capacity then flexible capacity must be added.



Day Ahead required load following capacity with 95 % confidence range



Required load following capacity with 95 % confidence range



Slide 12

Load, wind and solar forecast errors used in existing studies

Load Forecast Error By Season				
Season	Spring	Summer	Fall	Winter
Hour-Ahead Load Forecast Error (MW)	545.18	636.03	539.69	681.86
Real Time Load Forecast Error (MW)	216.05	288.03	277.38	230.96

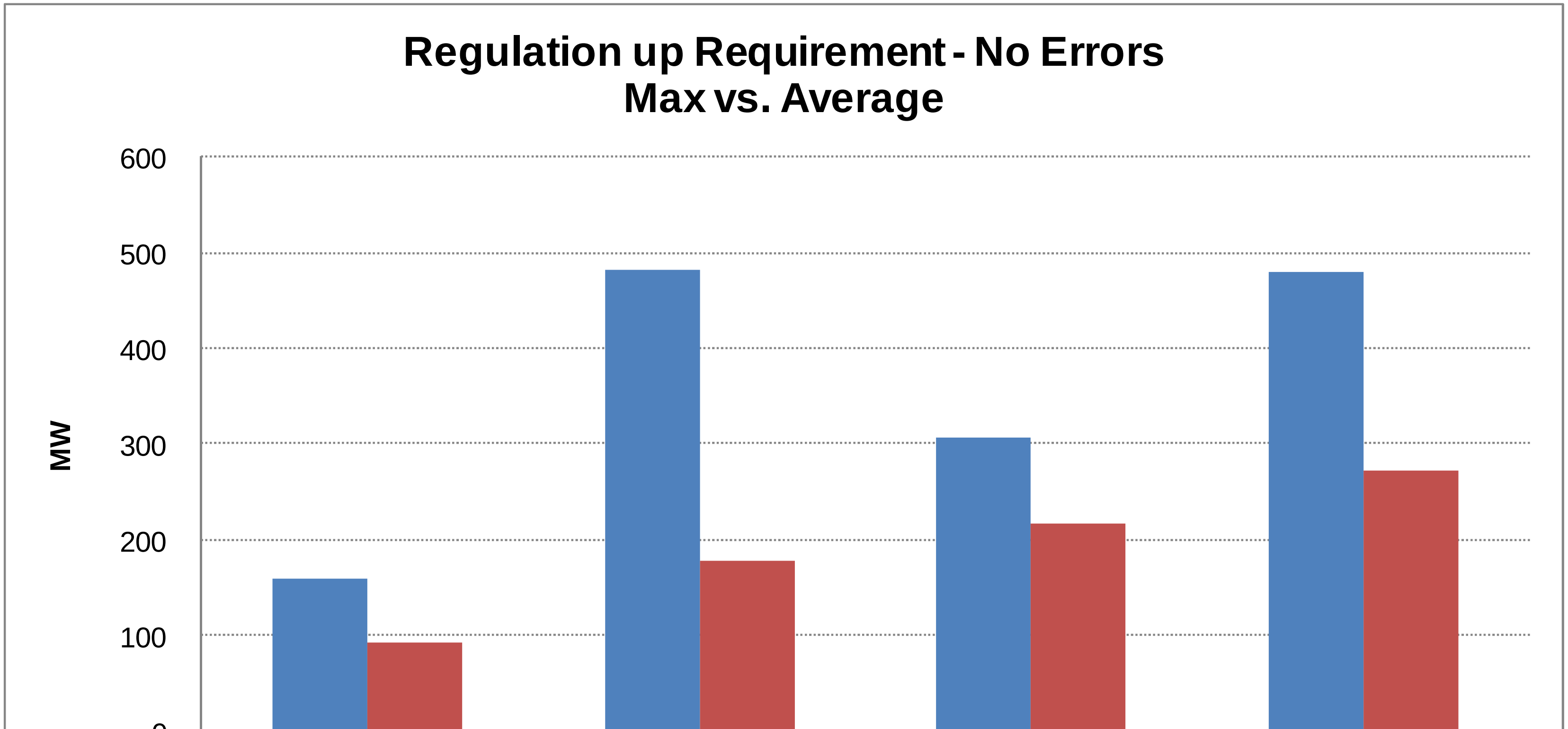
Hour-Ahead Wind Forecast Error by Season						
Technology	Persistent**	Hour	Spring	Summer	Fall	Winter
Wind	T-1	All	4.0%	3.8%	3.2%	3.1%

**Using aggregated hourly profile (T-1) persistent forecast for wind production to estimate the wind forecast error.

Hour-Ahead Solar Forecast Error by Clearness Index (CI)						
Technology	Persistent*	Hour	0<=CI<0.2	0.2<=CI<0.5	0.5<=CI<0.8	0.8<=CI<=1
Large PV (PV)	T-1	Hour12-16	3.5%	6.9%	5.6%	2.3%
Large Solar Thermal (ST)	T-1	Hour12-16	6.0%	10.9%	10.8%	3.0%
Distribute PV (DG)	T-1	Hour12-16	2.2%	4.7%	3.9%	1.8%
Customer Side PV (CPV)	T-1	Hour12-16	1.6%	3.3%	3.1%	1.6%

* Using the aggregated hourly profile (T-1) persistent forecast for CI to estimate the Solar forecast error.

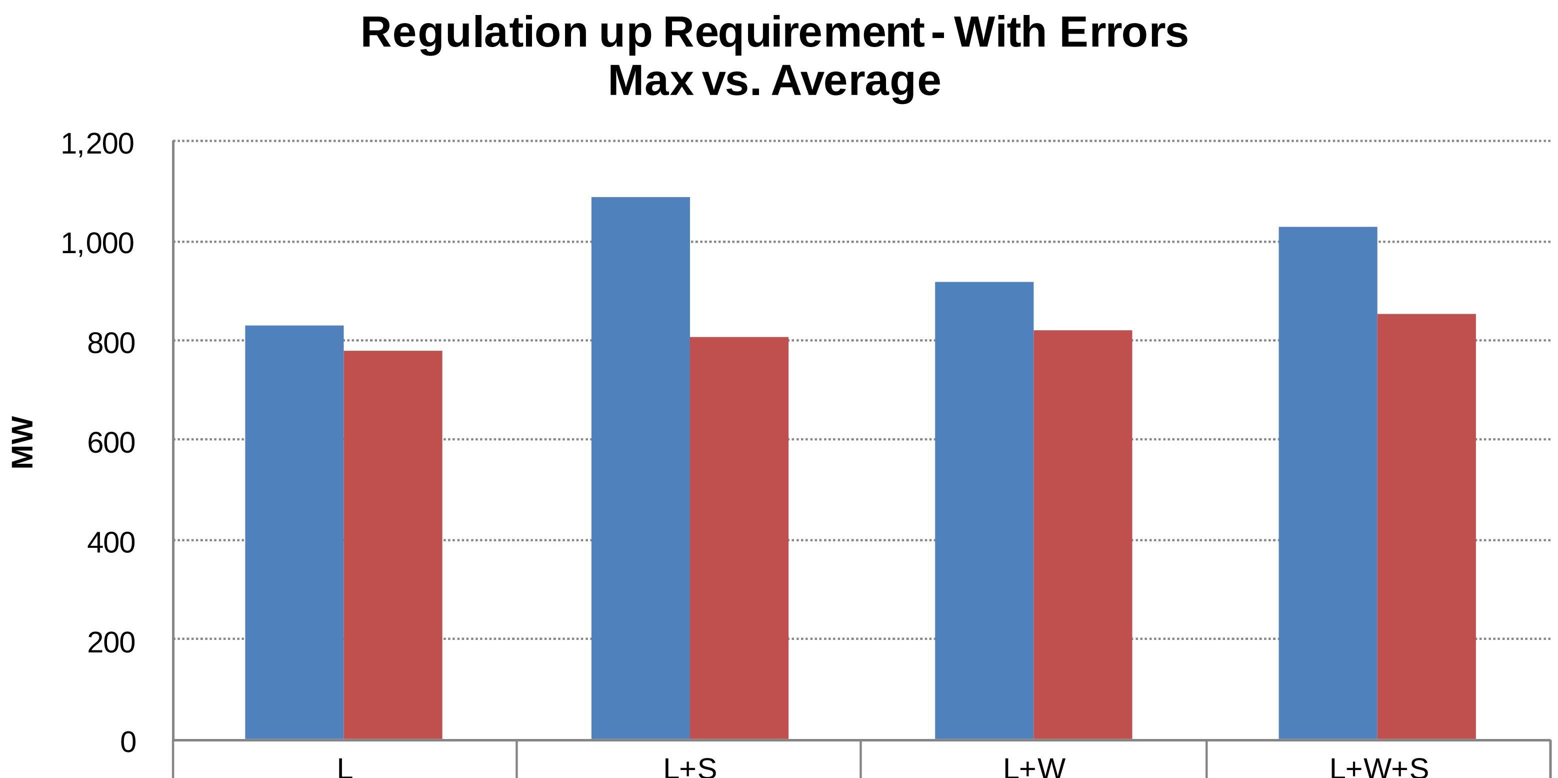
Comparison of maximum and average regulation up requirements for different combinations of load, wind and solar --- no errors



	L	L+S	L+W	L+W+S
Max	160	482	306	478
Average	94	177	217	272

Trajectory Case

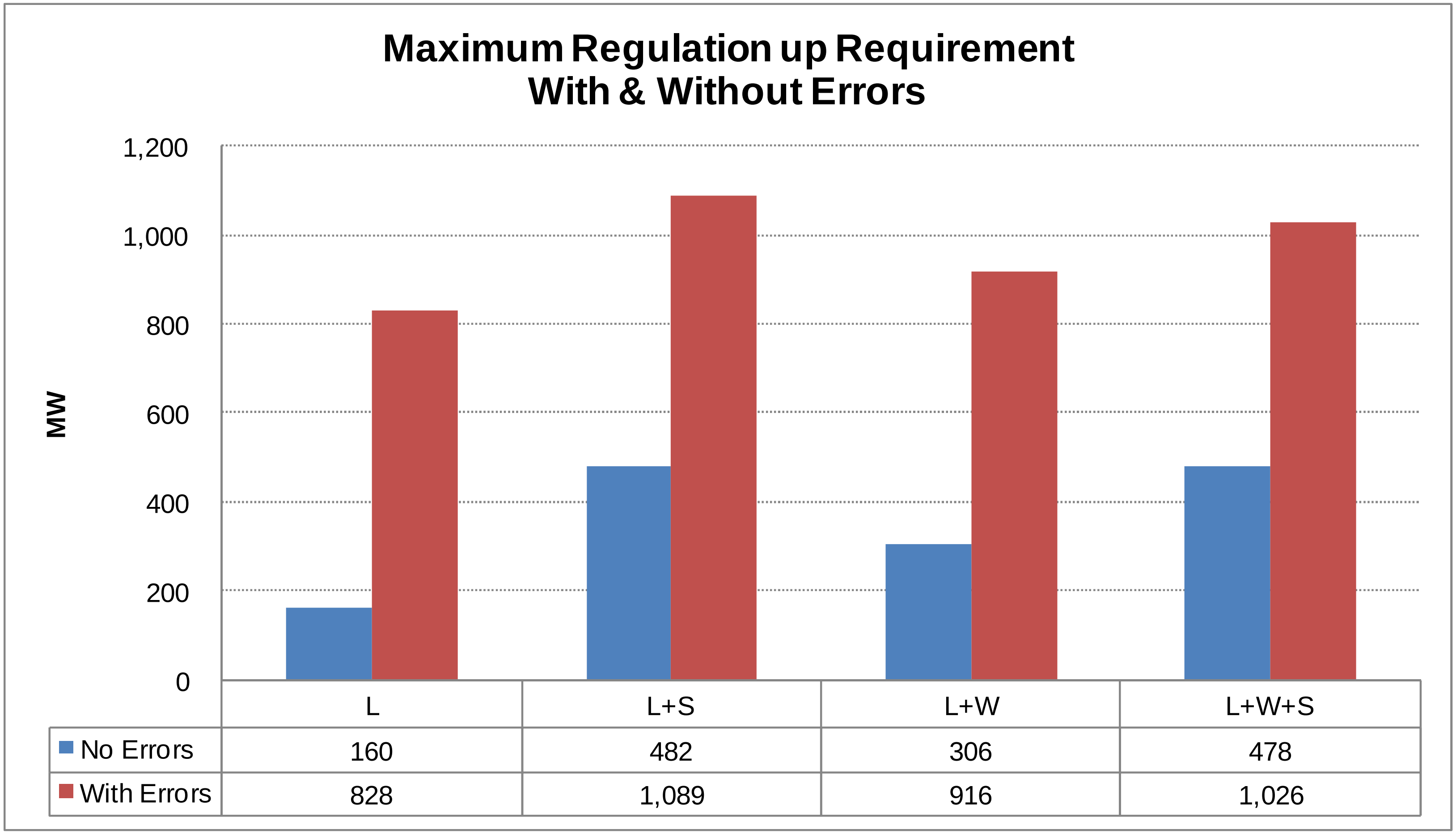
Comparison of maximum and average regulation up requirements for different combinations of load, wind and solar --- with errors



	L	L+S	L+W	L+W+S
Max	828	1,089	916	1,026
Average	778	808	822	852

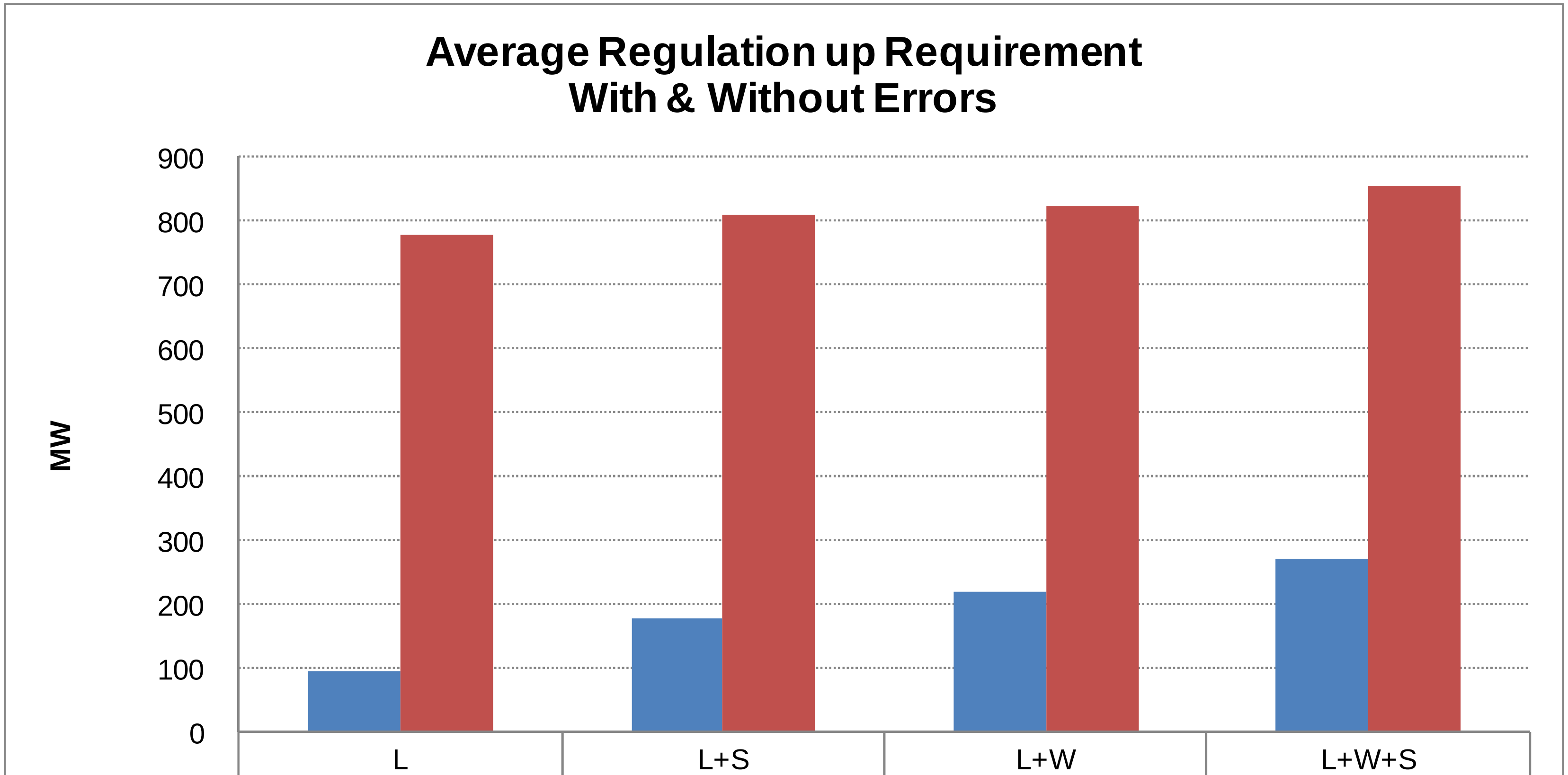
Trajectory Case

Maximum regulation up requirements for different combinations of load, wind and solar – with & without errors



Trajectory Case

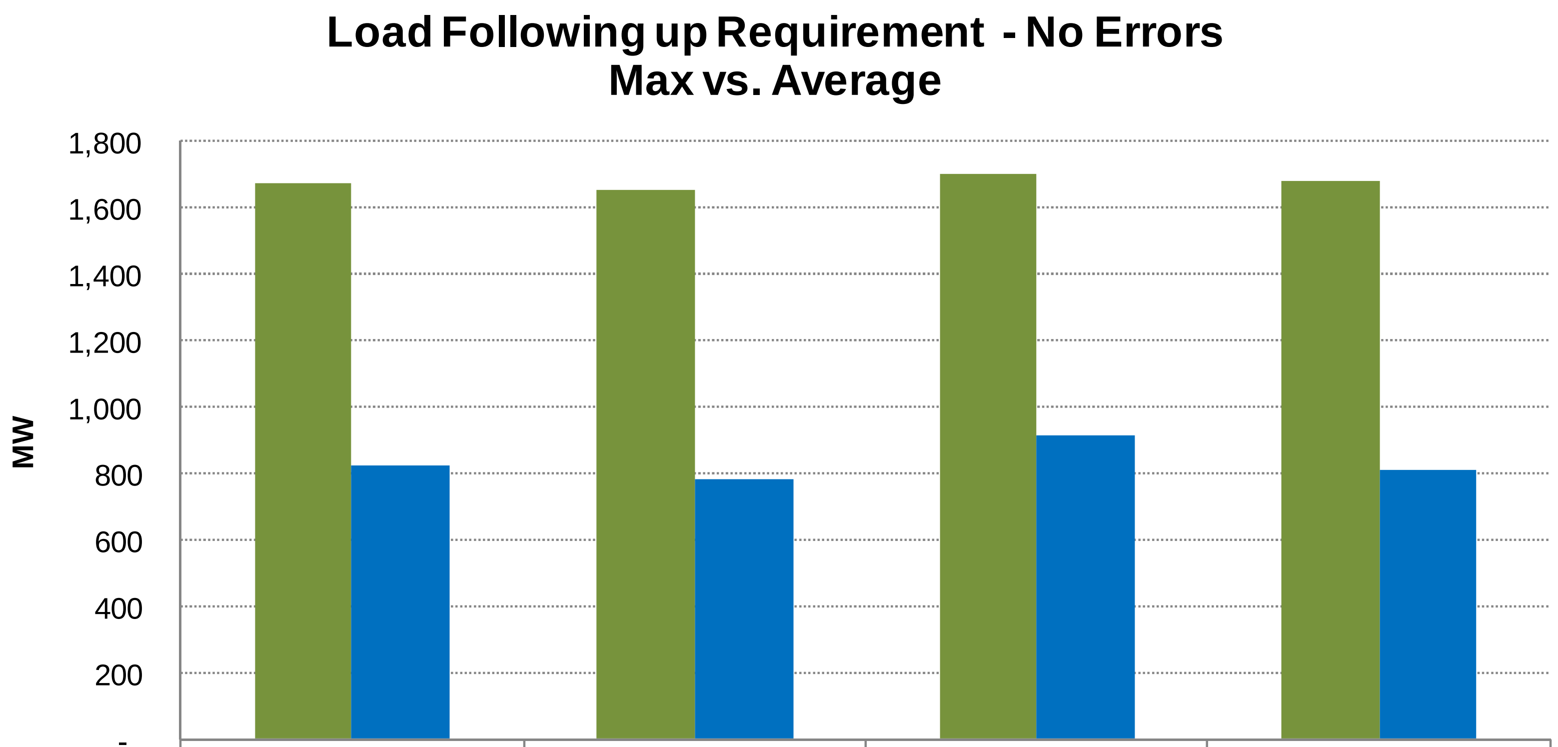
Average regulation up requirements for different combinations of load, wind and solar – with & without errors



	L	L+S	L+W	L+W+S
No Errors	94	177	217	272
With Errors	778	808	822	852

Trajectory Case

Comparison of maximum and average load following up requirements for different combinations of load, wind and solar --- no errors

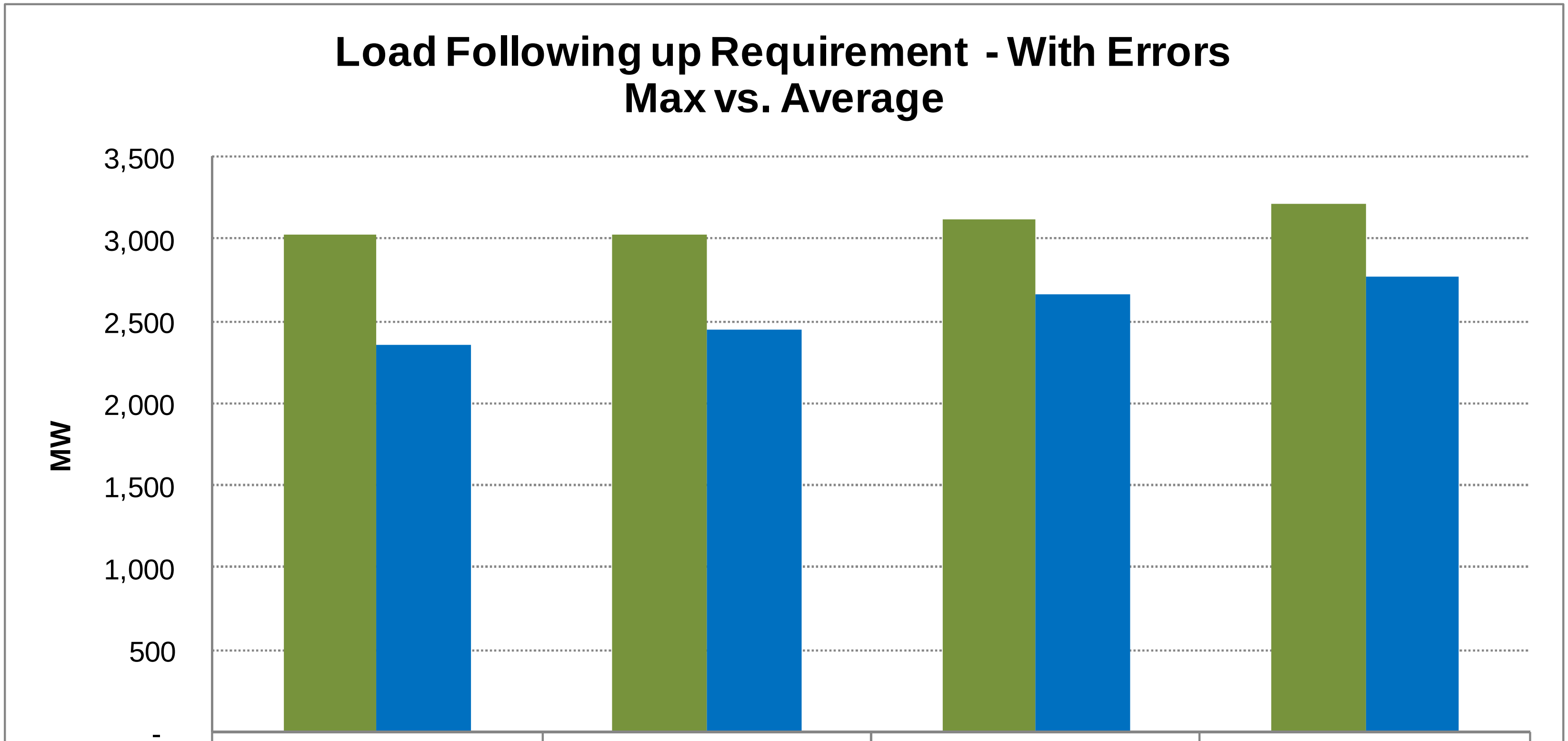


	L	L+S	L+W	L+W+S
Max	1,674	1,651	1,703	1,681
Average	823	781	917	809

Trajectory Case

Slide 8

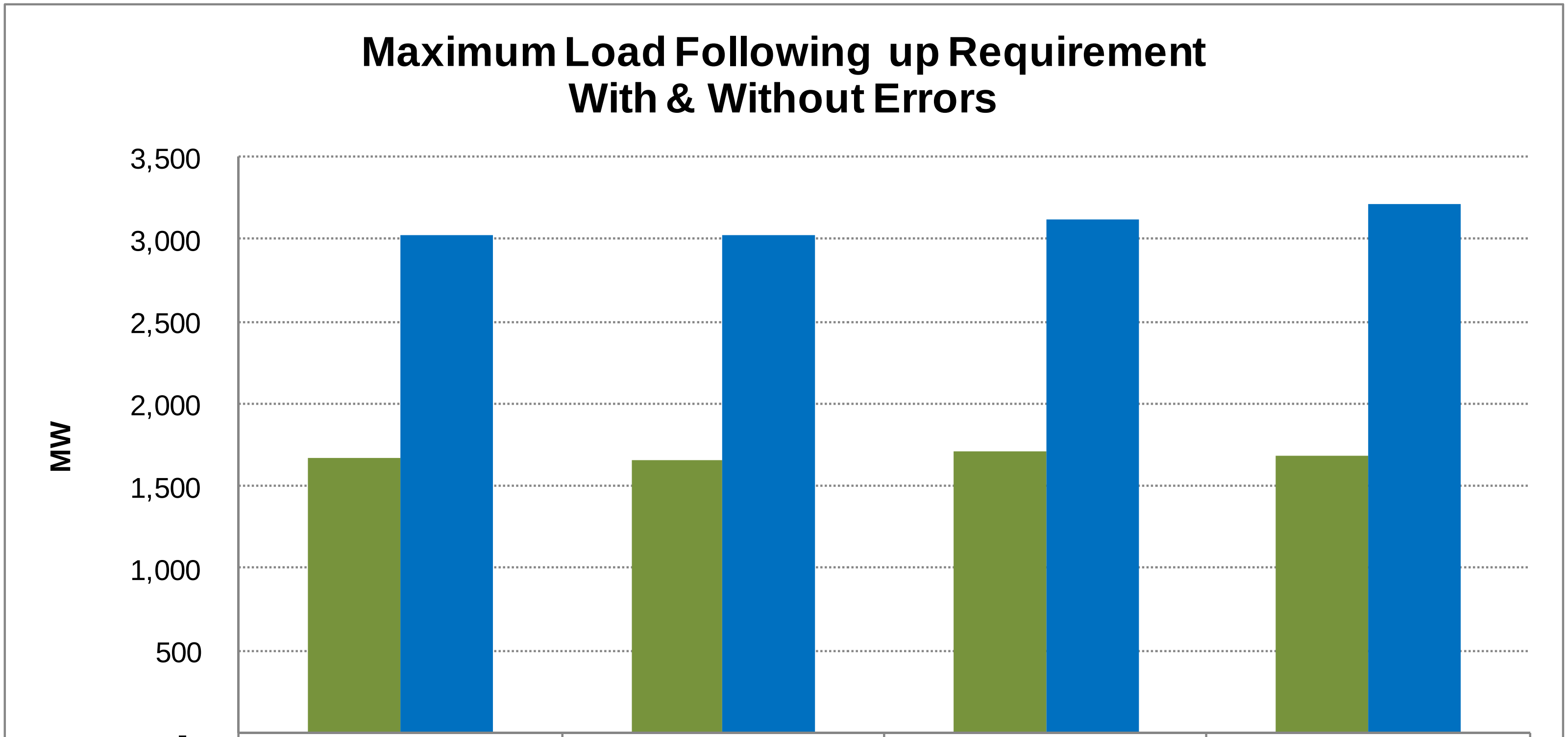
Comparison of maximum and average load following up requirements for different combinations of load, wind and solar --- with errors



	L	L+S	L+W	L+W+S
Max	3,027	3,027	3,123	3,210
Average	2,350	2,444	2,663	2,769

Trajectory Case

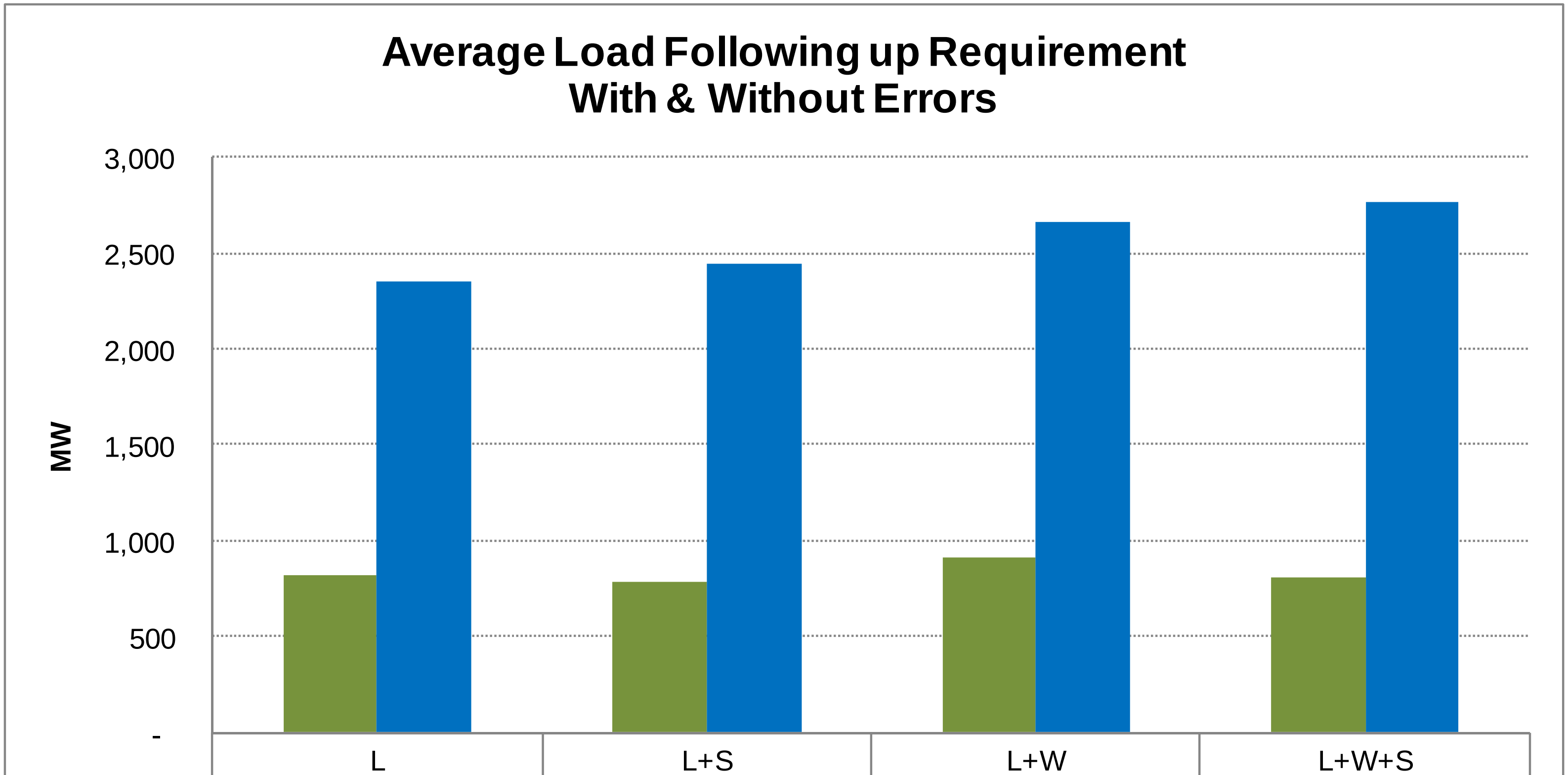
Maximum load following up requirements for different combinations of load, wind and solar – with & without errors



	L	L+S	L+W	L+W+S
No Errors	1,674	1,651	1,703	1,681
With Errors	3,027	3,027	3,123	3,210

Trajectory Case

Average load following up requirements for different combinations of load, wind and solar – with & without errors

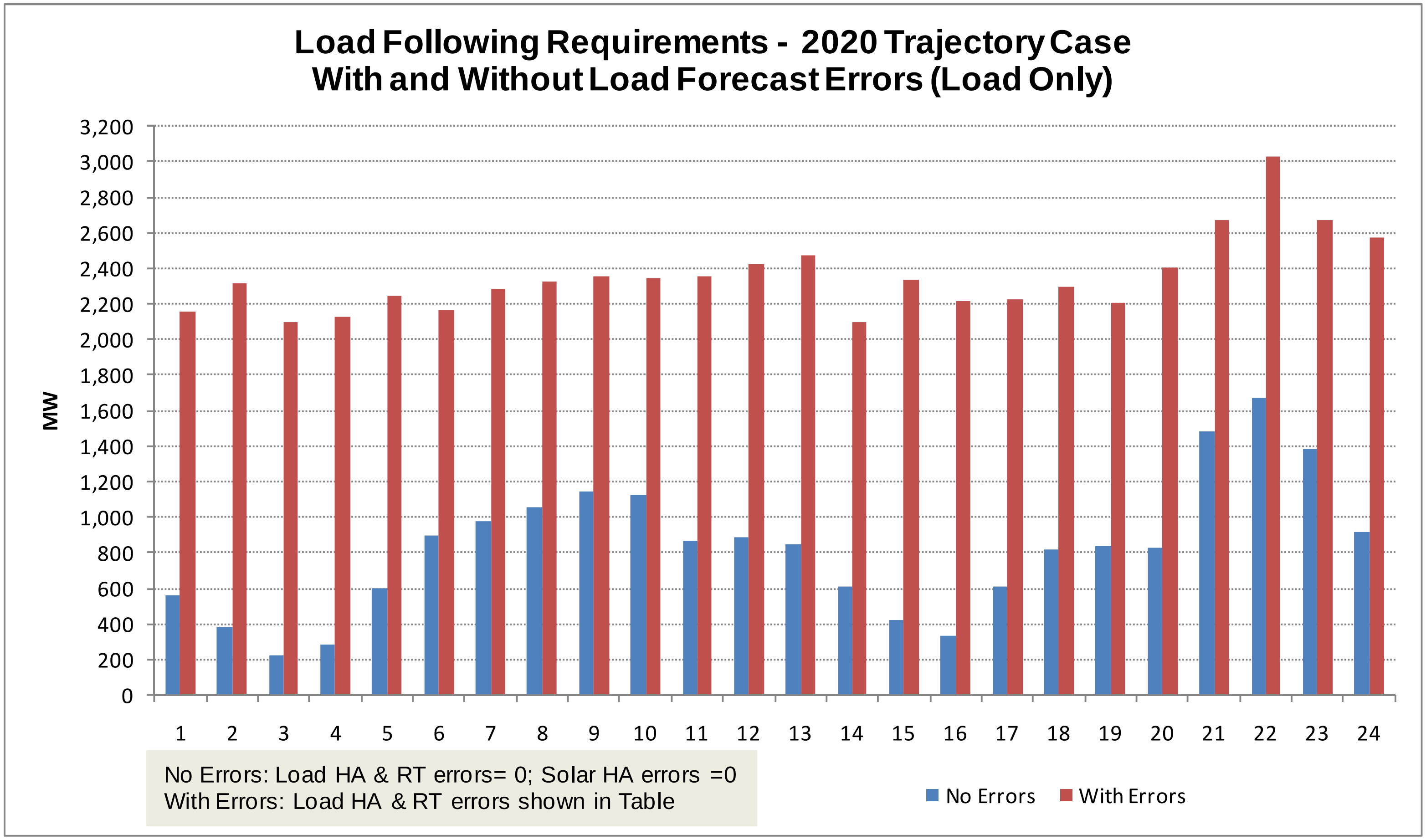


	L	L+S	L+W	L+W+S
Series1	823	781	917	809
Series2	2,350	2,444	2,663	2,769

Trajectory Case

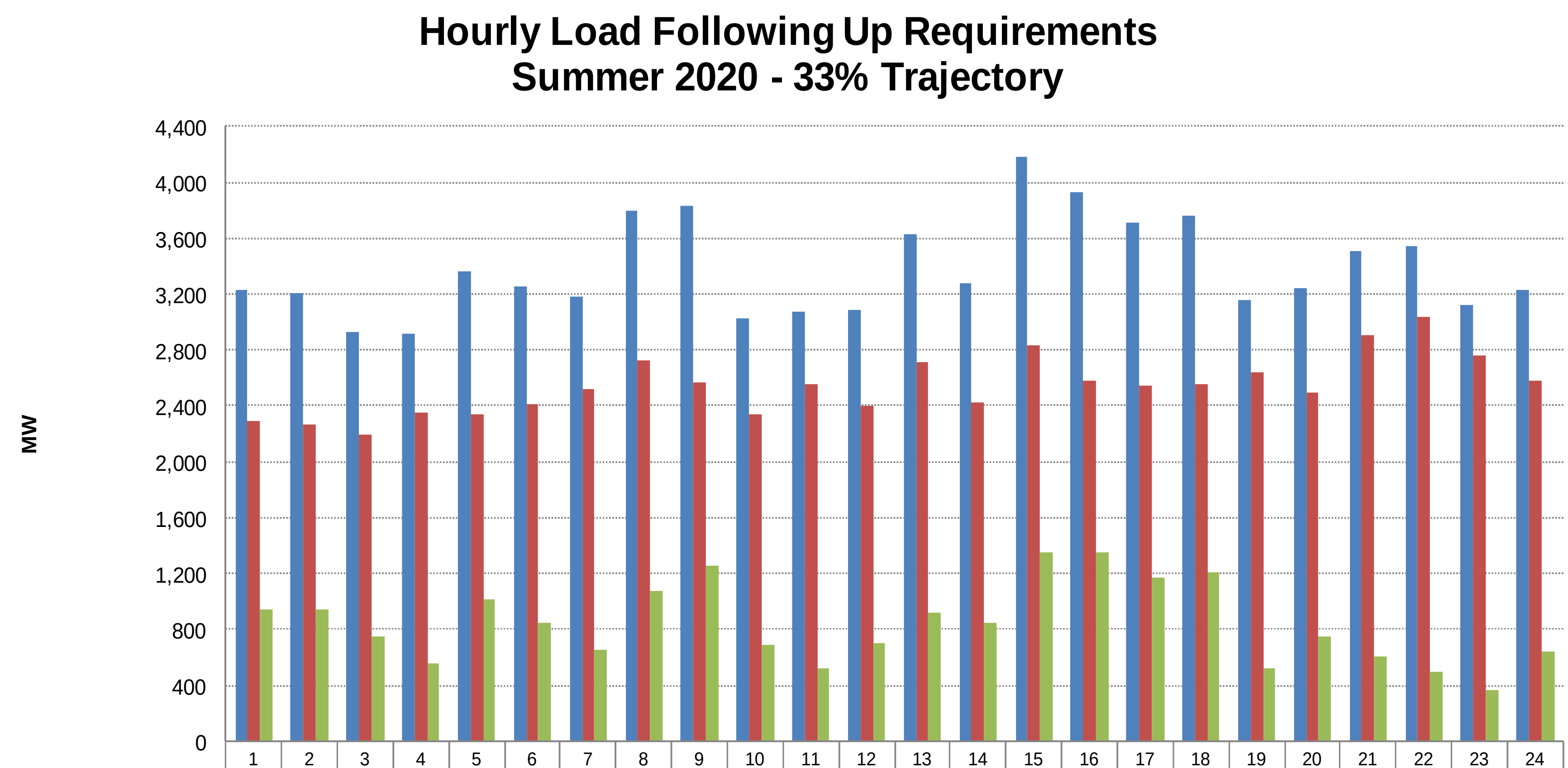
Slide 11

Maximum load following up requirements for different combinations of load, wind and solar – with & without errors



Trajectory Case

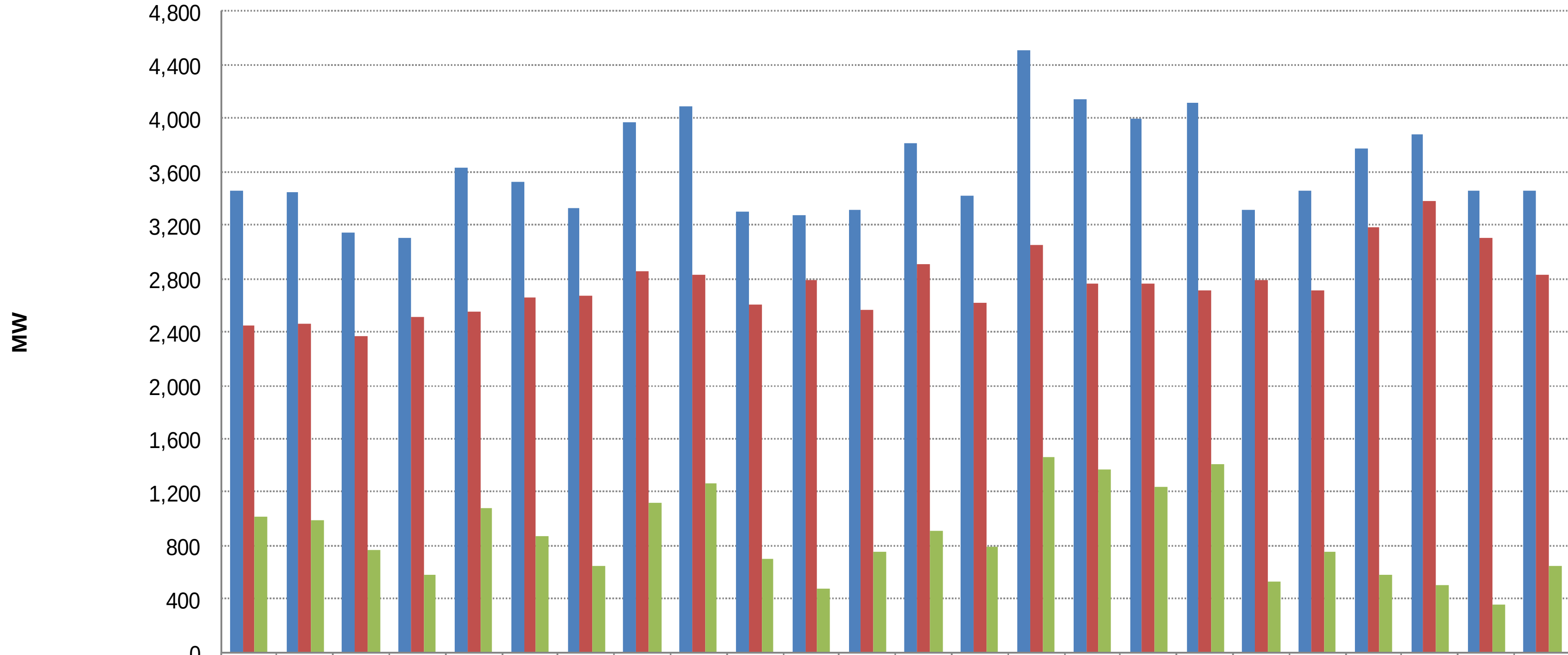
Hourly load following up requirement for the Trajectory scenario



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Trajectory (High Errors)	3,229	3,209	2,934	2,913	3,363	3,252	3,180	3,798	3,827	3,029	3,072	3,091	3,627	3,275	4,183	3,927	3,707	3,761	3,163	3,243	3,509	3,546	3,128	3,229
Trajectory (Low Errors)	2,288	2,264	2,189	2,354	2,343	2,409	2,521	2,728	2,573	2,342	2,551	2,394	2,710	2,428	2,831	2,579	2,538	2,556	2,643	2,495	2,903	3,043	2,762	2,581
Difference	941	944	745	559	1,021	842	659	1,071	1,254	687	521	696	917	847	1,352	1,348	1,169	1,205	520	748	606	503	366	648

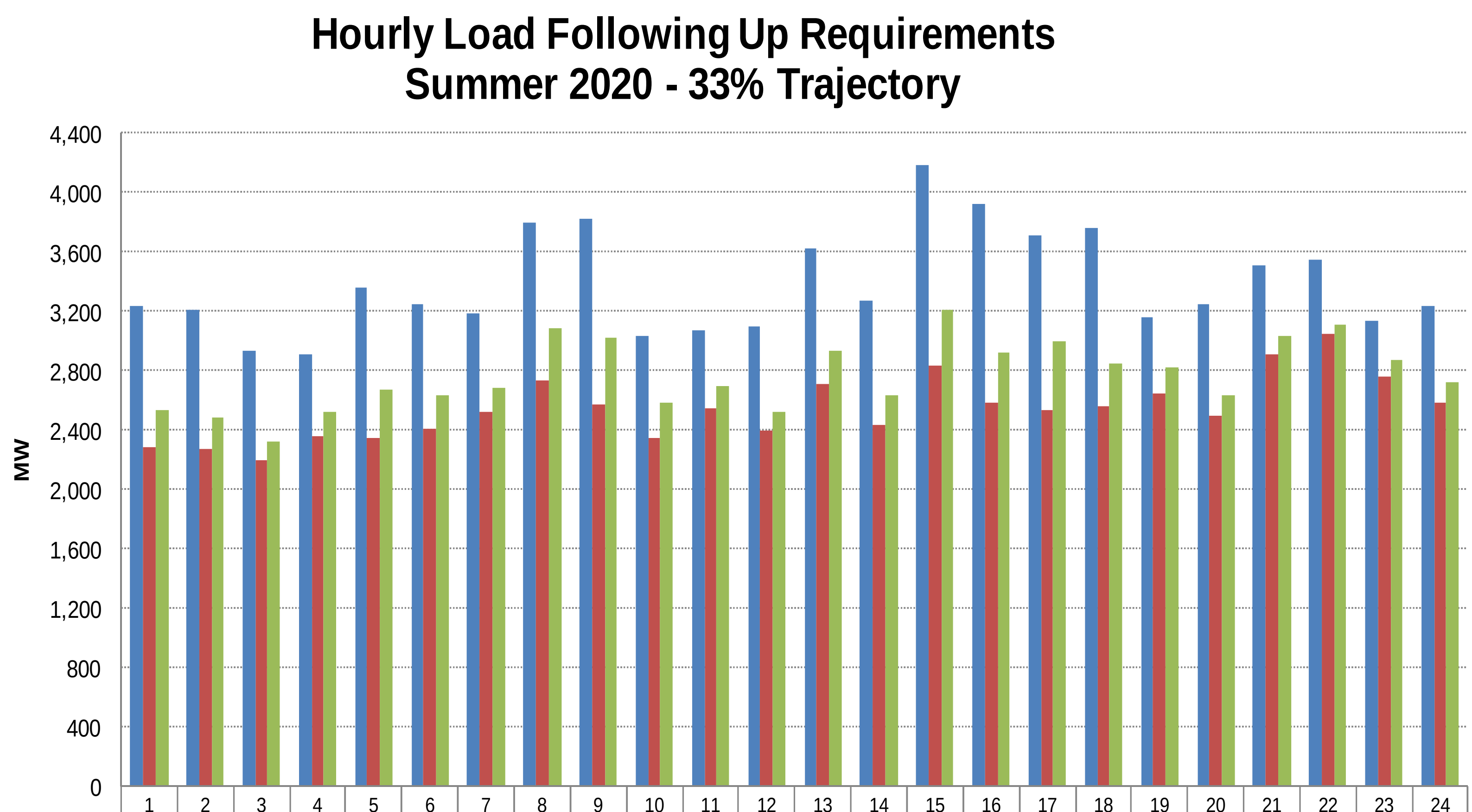
Hourly load following up requirement comparison for the High Load scenario

Hourly Load Following Up Requirements
Summer 2020 - 33% High Load



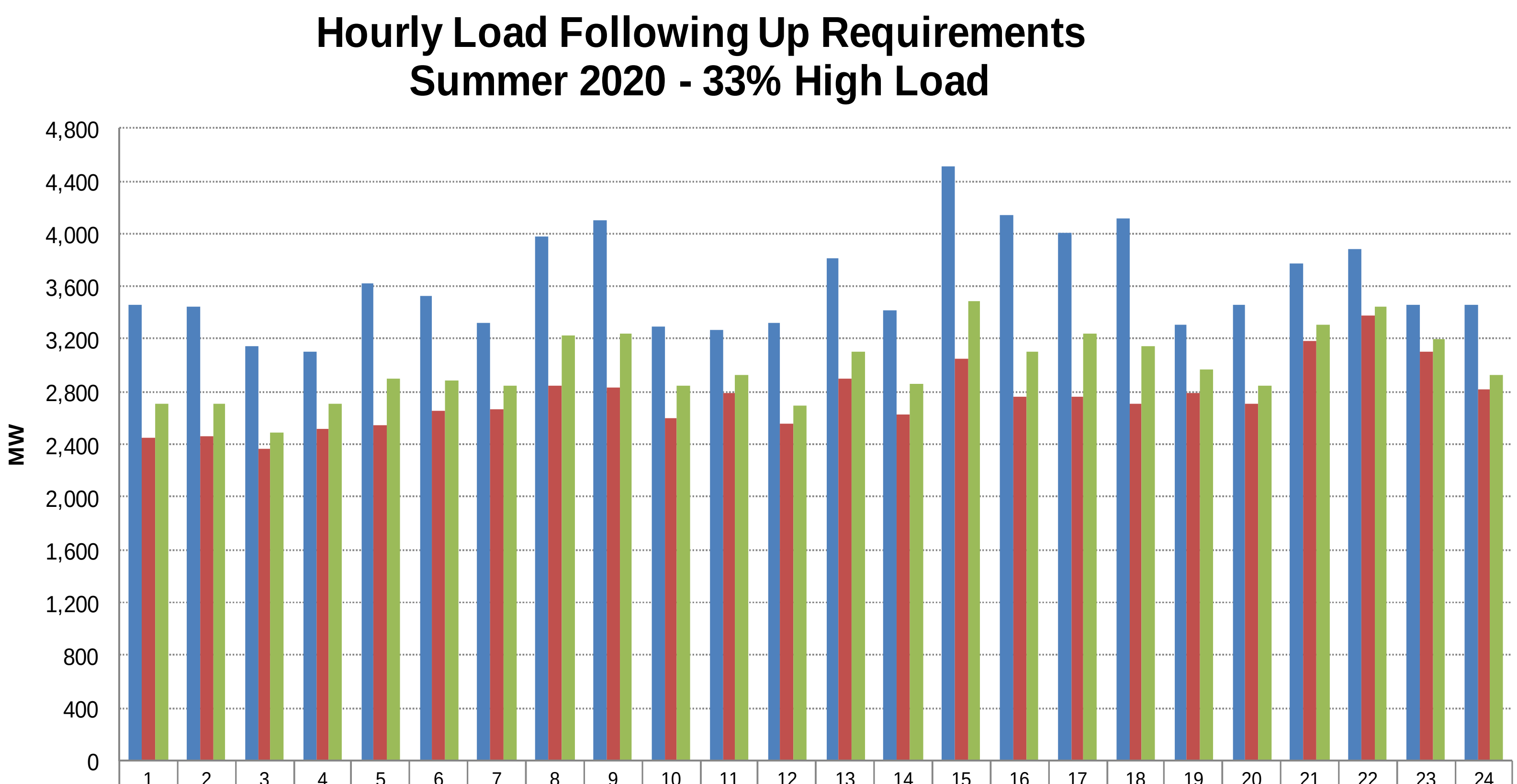
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
High Load (High Errors)	3,454	3,450	3,141	3,102	3,626	3,529	3,325	3,973	4,094	3,296	3,274	3,319	3,814	3,417	4,515	4,142	3,999	4,113	3,312	3,464	3,768	3,883	3,458	3,465
High Load (low Errors)	2,443	2,460	2,373	2,515	2,551	2,657	2,672	2,849	2,834	2,601	2,795	2,561	2,904	2,624	3,053	2,767	2,766	2,706	2,783	2,706	3,185	3,376	3,104	2,822
Difference	1,011	990	768	587	1,075	873	653	1,124	1,260	695	479	758	910	793	1,462	1,376	1,233	1,407	528	758	584	507	355	643

Hourly load following up requirement for the Trajectory scenario -- high and low forecast errors and T-1 errors



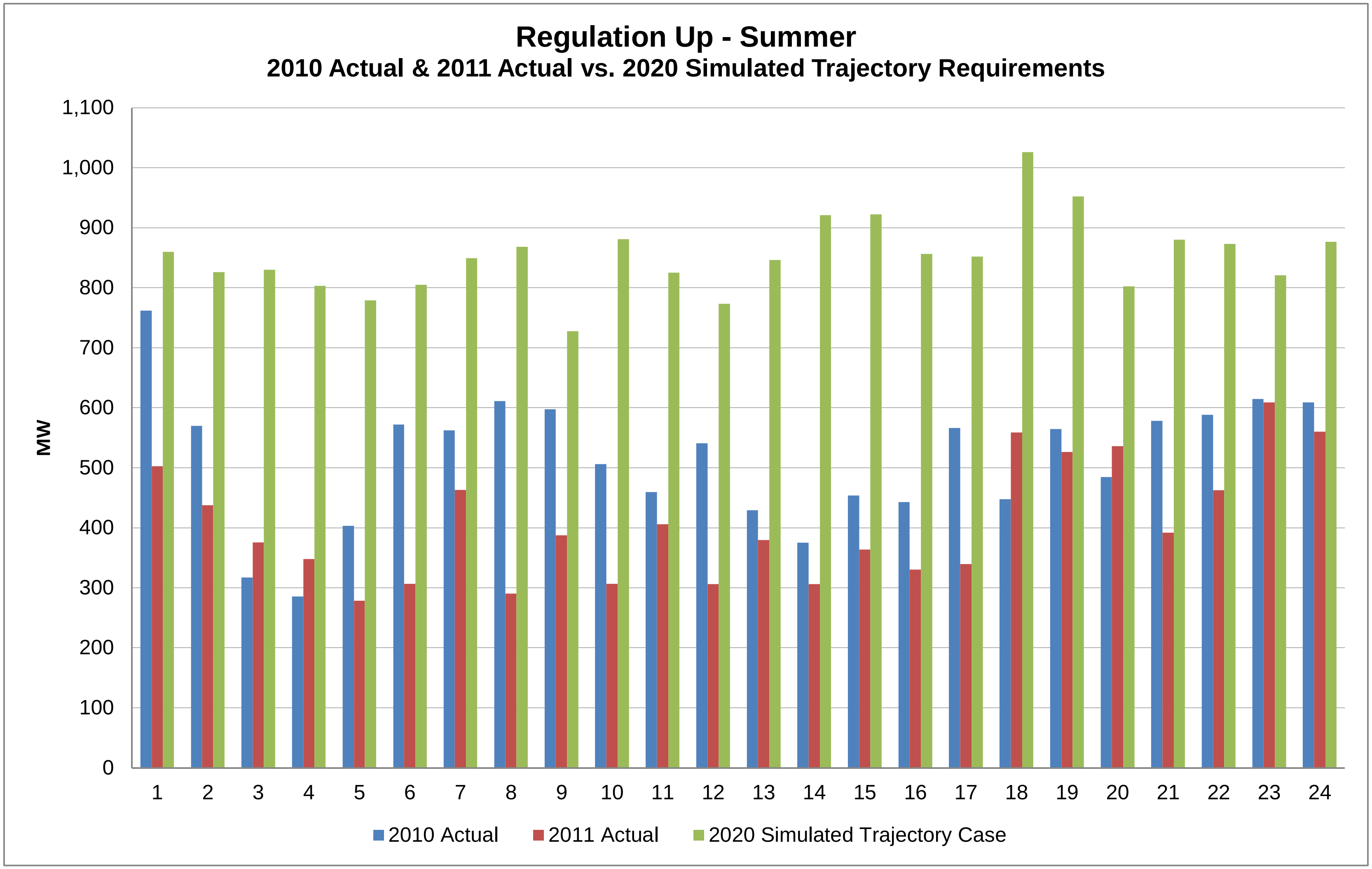
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Trajectory (High Errors)	3,229	3,209	2,934	2,913	3,363	3,252	3,180	3,798	3,827	3,029	3,072	3,091	3,627	3,275	4,183	3,927	3,707	3,761	3,163	3,243	3,509	3,546	3,128	3,229
Trajectory (Low Errors)	2,288	2,264	2,189	2,354	2,343	2,409	2,521	2,728	2,573	2,342	2,551	2,394	2,710	2,428	2,831	2,579	2,538	2,556	2,643	2,495	2,903	3,043	2,762	2,581
T-1 Forecast Errors	2,530	2,486	2,315	2,522	2,665	2,631	2,686	3,086	3,015	2,584	2,691	2,520	2,927	2,639	3,210	2,924	2,990	2,851	2,816	2,630	3,033	3,114	2,864	2,714

Hourly load following up requirement for the High Load scenario - high and low forecast errors and T-1 errors



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
High Load (High Errors)	3,454	3,450	3,141	3,102	3,626	3,529	3,325	3,973	4,094	3,296	3,274	3,319	3,814	3,417	4,515	4,142	3,999	4,113	3,312	3,464	3,768	3,883	3,458	3,465
High Load (low Errors)	2,443	2,460	2,373	2,515	2,551	2,657	2,672	2,849	2,834	2,601	2,795	2,561	2,904	2,624	3,053	2,767	2,766	2,706	2,783	2,706	3,185	3,376	3,104	2,822
T-1 Forecast Errors	2,715	2,702	2,487	2,703	2,902	2,892	2,839	3,230	3,240	2,848	2,921	2,701	3,111	2,864	3,492	3,105	3,242	3,151	2,972	2,847	3,309	3,446	3,204	2,921

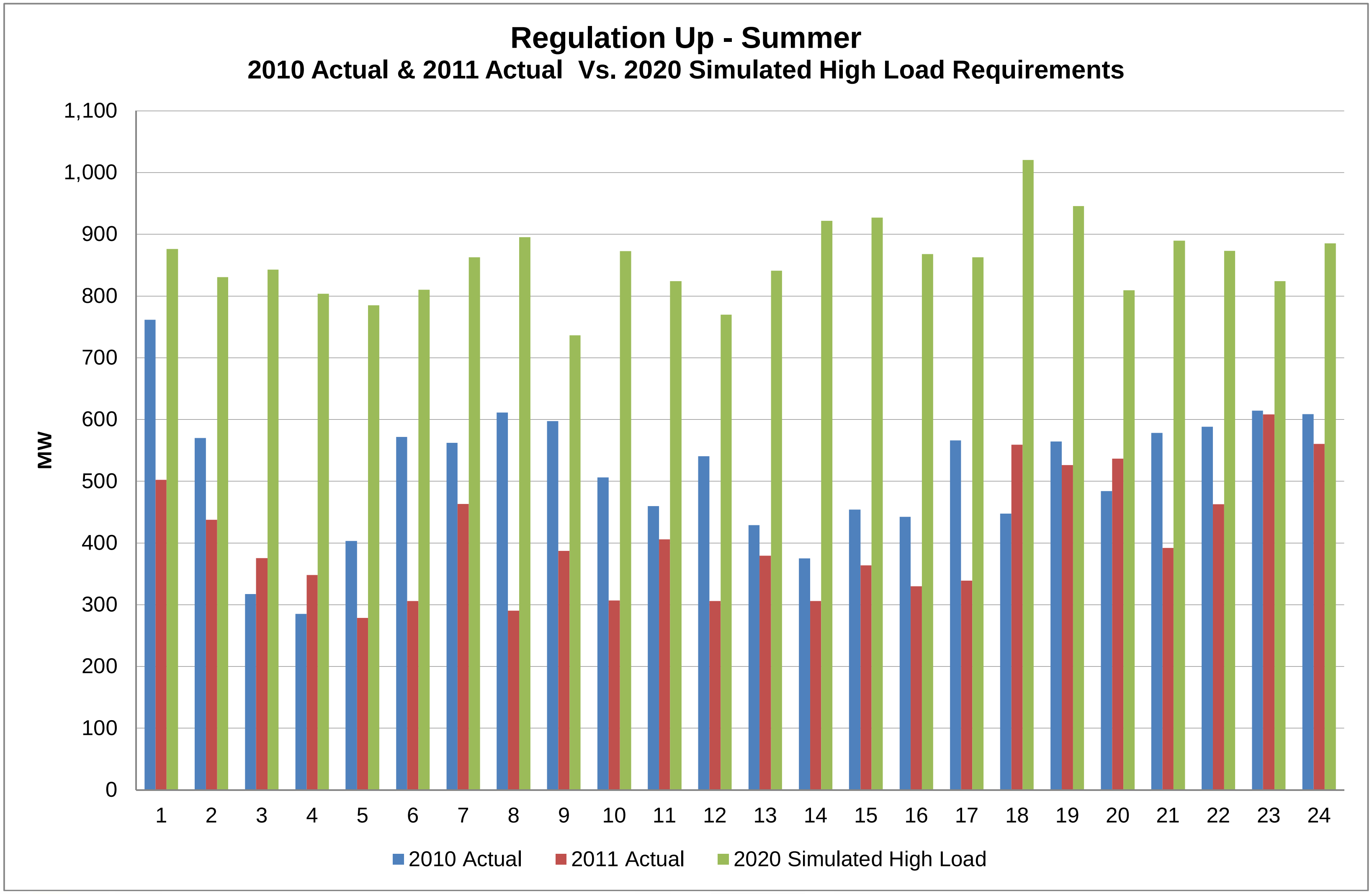
Regulation up actuals vs. simulated (Trajectory Case)



California ISO
Shaping a Renewed Future

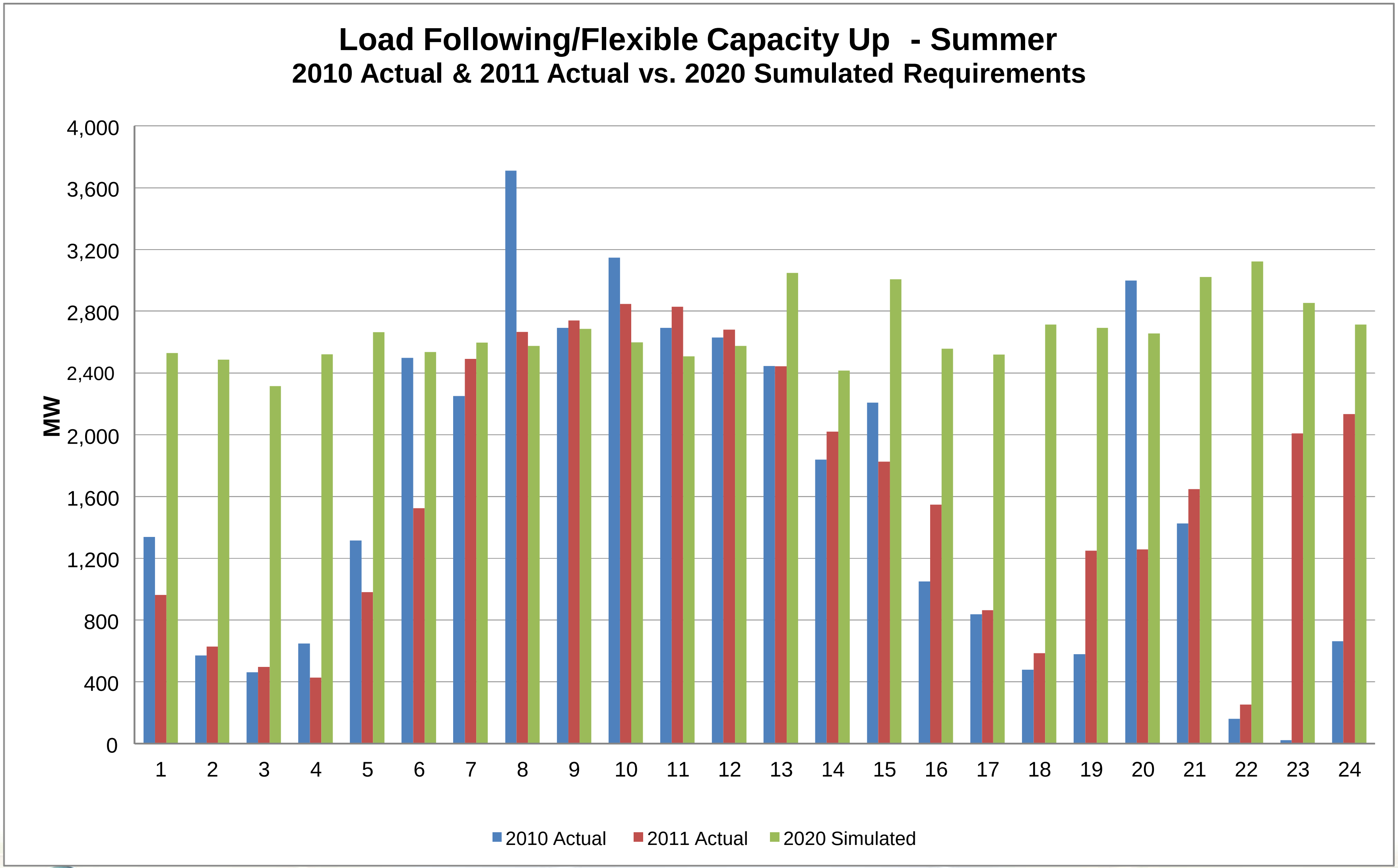
Slide 165

Regulation up actuals vs. simulated (High Load Case)



Slide 166

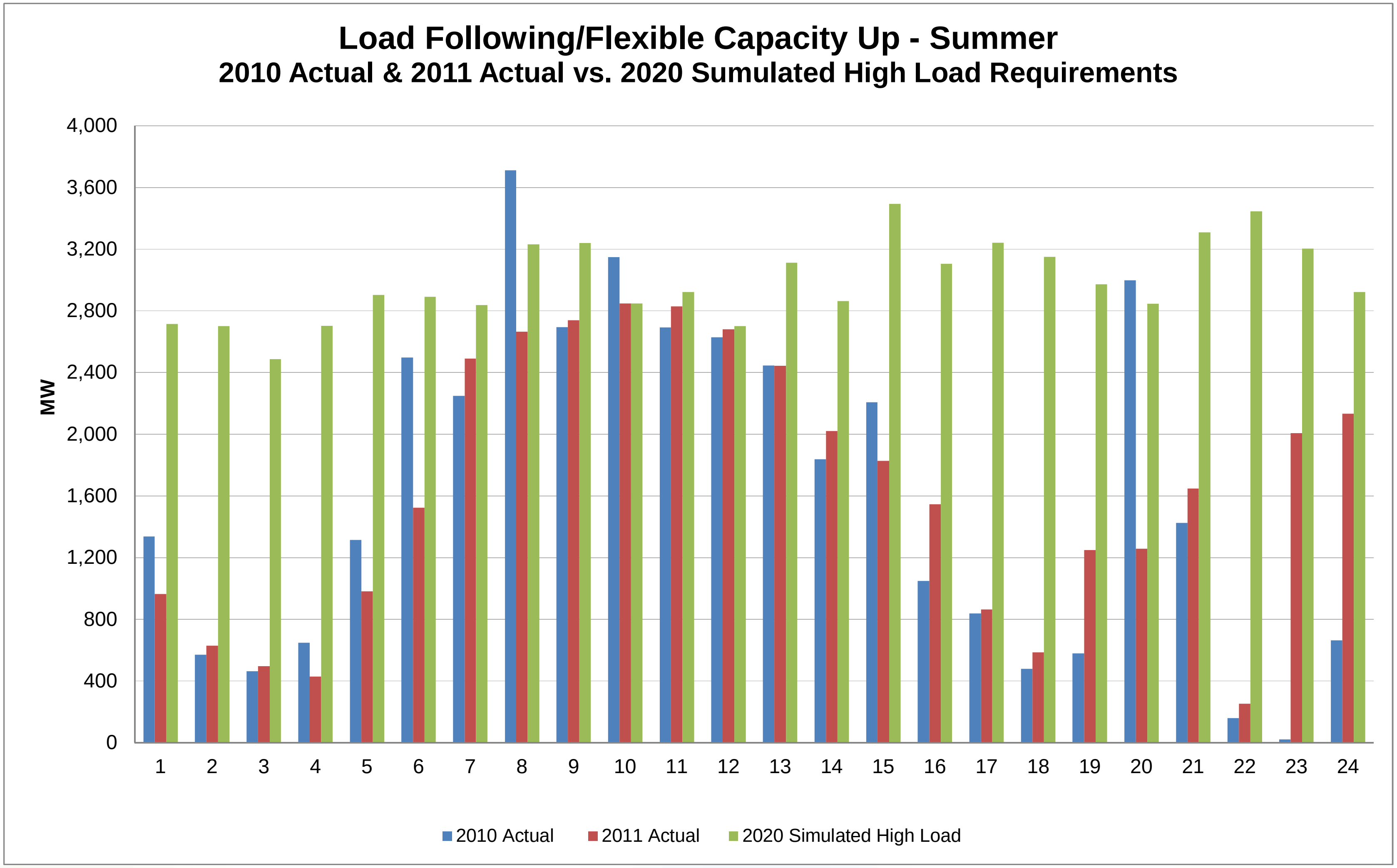
Load Following/Flexibility Capacity actuals vs. simulated (Trajectory Case)



California ISO
Shaping a Renewed Future

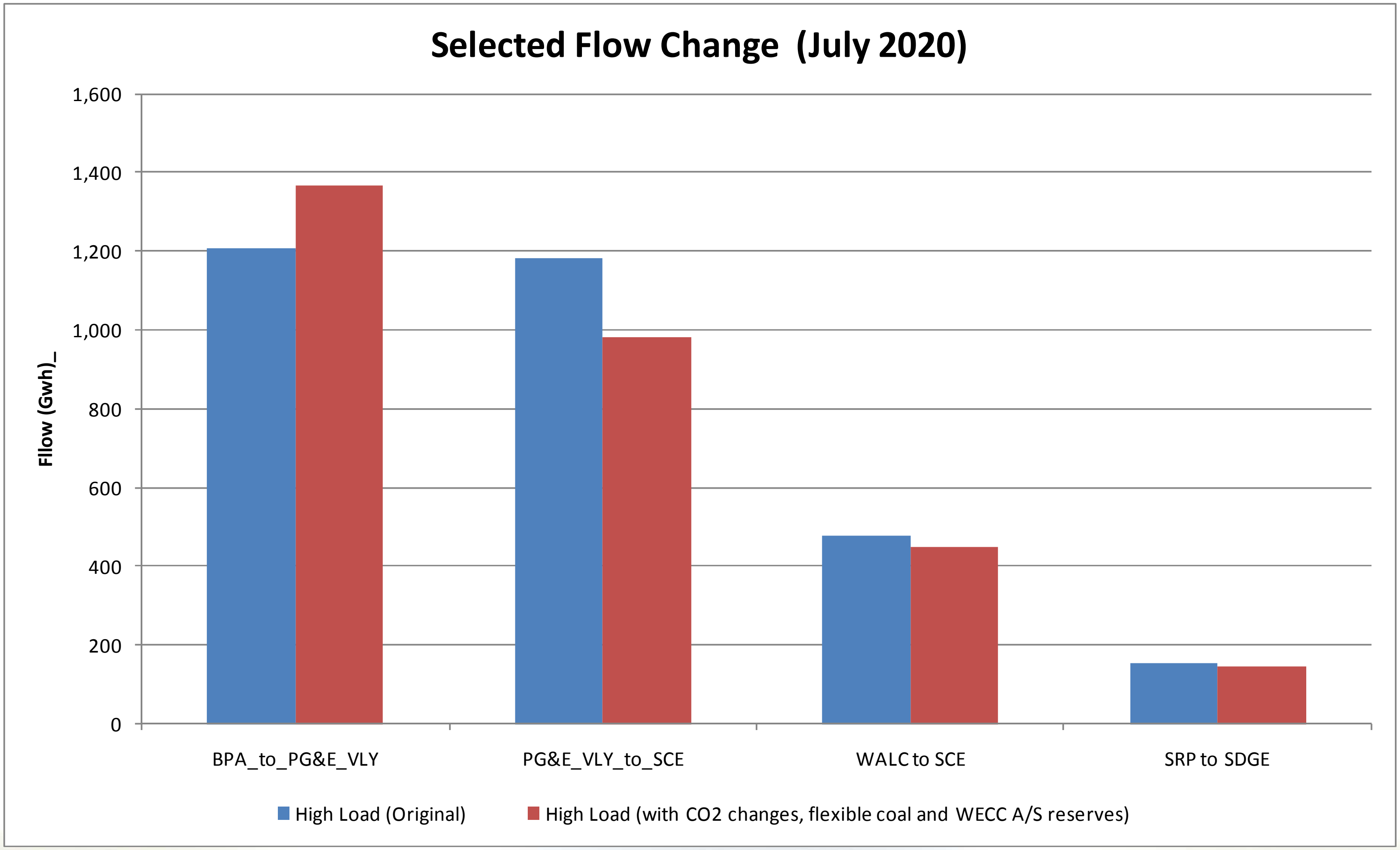
Slide 167

Load Following/Flexibility Capacity actuals vs. simulated (High Load Case)



Slide 168

Changes to GHG and coal flexibility modeling observed increase capacity factor of external Coal resources.



California ISO
Shaping a Renewed Future